Q. Re: Production Life: Please provide a complete copy of all studies performed by the Company during the past 10 years associated with the economics of rehabilitating and continuing use or retirements of generating structures.

A. Please see attached reports:

1) CA-NLH-52 Attachment 1 - Holyrood Thermal Generating Station - Condition Assessment & Life Extension Study - AMEC

2) CA-NLH-52 Attachment 2 - Final Report - Condition Assessment and Life cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities - Stantec

3) CA-NLH-52 Attachment 3 - Holyrood Thermal Generating Station - Gas Turbine Condition Assessment & Options Study - AMEC

4) CA-NLH-52 Attachment 4a - Snook's Arm Wood Stave Penstock - Evaluation, Recommendation and Estimated Cost for Replacement - NLH

5) CA-NLH-52 Attachment 4b - Snook's Arm Wood Stave Penstock - Report Addendum - Update of Economic Analysis – NLH

6) CA-NLH-52 Attachment 5a - St. Lewis - Port Hope Simpson Interconnection Economic Analysis – NLH

7) CA-NLH-52 Attachment 5b - St. Lewis - Port Hope Simpson Interconnection Economic Analysis - Detail - NLH

28 January 2011

Mr. Todd Collins, P. Eng.
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Dear Todd,

Holyrood Thermal Generating Station (Holyrood) Condition Assessment & Life Extension Study, - Final Report

As per our Agreement, we have completed the Holyrood Thermal Generating Station Condition Assessment & Life Extension Study Report. I trust that the report satisfies your needs.

Thank you for the opportunity to work on this very interesting project.

Yours truly,



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# Holyrood Thermal Generating Station
# Condition Assessment & Life Extension Study

**January 28, 2011**

# Holyrood Thermal Generating Station
# Condition Assessment & Life Extension Study

Blair Seckington
Prepared by: Date

Ian Leach
Checked by: Date

Bob Livet
Approved by: Date

| Rev. | Description | Prepared By: | Checked: | Approved | Date |
|---|---|---|---|---|---|
| A | Draft Report | Blair Seckington | | | 28 Jun 10 |
| 0 | Final Report | Blair Seckington | Ian Leach | | 28 Jan 11 |
| | | | | | |
| | | | | | |

## IMPORTANT NOTICE

This report was prepared exclusively for Newfoundland and Labrador Hydro, a NALCOR Energy Company, by AMEC Americas Limited. The quality of information, conclusions and estimates contained herein is consistent with the level of effort involved in AMEC Americas Limited services and is based on: i) information available at the time of preparation; ii) data supplied by outside sources; and iii) the assumptions, conditions, and qualifications set forth in this report. This report is intended to only be used by Newfoundland and Labrador Hydro, a NALCOR Energy Company, including as support for planning and regulatory filings with its regulatory body, subject to the terms and conditions of its contract with AMEC Americas Limited. Any other use of, or reliance on, this report by any third party for purposes unrelated to Newfoundland and Labrador Hydro a NALCOR Energy Company's planning and regulatory proceedings is at that party's sole risk.

## APPENDICES

Significant detailed technical information on equipment and systems was initially developed as input to this report. This information is documented in Appendices 4 through 34. The additional detailed information in these Appendices is intended primarily for the reference use of Hydro engineering and plant technical specialists. These appendices should be considered as "Working Papers".

# Executive Summary

# HOLYROOD THERMAL GENERATING STATION
# CONDITION ASSESSMENT AND LIFE EXTENSION STUDY

## EXECUTIVE SUMMARY

### Introduction

Holyrood Thermal Generating Station (Holyrood) is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

Units 1 and 2 were built in the late 1960's as #6 fuel oil fired 150 MW units. Unit 1 entered service in September 1970 and Unit 2 in April 1971. These two units were modified in 1987 to increase their capacity to 175 MW. Unit 3 is a 150 MW unit and was built in 1979 and came online in February 1980.

### Holyrood Phase 1 Condition Assessment Study

AMEC Americas Limited (AMEC) was contracted by Newfoundland and Labrador Hydro (Hydro), a NALCOR Energy Company, to conduct Phase 1 of a Condition Assessment and Life Extension Study for the Holyrood Generating Station.

The basis for the study was essentially:

- 2010 to 2015 Electricity Generation – similar to recent historical operation;
- 2015 to 2020 Electricity Generation - as-required, primarily "Standby" basis; and
- 2015 to 2041 Synchronous Condensing Operation – Units 1 and 2 converted to synchronous condensing capable in 2014/15 and all Units operating primarily in synchronous condensing mode to support system stability.

AMEC was to perform an initial condition assessment, generally referred in the electric utility industry as a "Level 1" assessment. This involved:

i. The review of existing maintenance and inspections information and plans, equipment and systems reviews with maintenance and operational staff, and independent visual walk-about inspections as appropriate.
ii. The development of equipment and systems assessments for:
    a. condition;
    b. action plans;
    c. technical and safety risk;
    d. life cycle status;
    e. level 2 inspection requirements; and
    f. capital investment timing.
iii. The development of key conclusions and recommendations.

The primary focus of the review was on the major equipment and systems that would be required for synchronous condensing mode operation to 2041 (i.e. generators, transformers, switchyard systems, electrical systems), but those systems required only for electricity generation to 2020 (i.e. boiler, steam turbine, fuel systems) were addressed with the 2020 end of life date as context.

**Overall Plant Assessment**

Holyrood is considered to be a relatively modern design plant and in good condition.

Holyrood is expected to be able to meet either the 2015 or 2020 dates for the end of its electricity generation role with capital refurbishments and replacements primarily due to typical mid-life refurbishment requirements, old age effects, and obsolescence. These are detailed later in the body of the report, but examples would include many of the breakers and motor control centres, the waste water treatment basin building structure and ventilation system, the plant elevator, and equipment such as vacuum pumps, emergency diesels and air compressors. To minimize a decrease in reliability, additional spares such as a spare 4 kV motor for each boiler feed pump, a forced draft fan, and a circulating water pump are recommended. A complete overhaul or replacement of the gas turbine generator and balance of plant would also be recommended, given its importance in a return to operation in the event of a system failure and its use as a system emergency power source.

Holyrood is also expected to be able to meet its 2041 end of life date for operation in a synchronous condensing mode, but will require some further substantial equipment refurbishments and replacements specific to that role. These are identified later in the report, but examples of these would include generator rewinds, powerhouse and pump house roof replacements, switchyard breakers and motorized switches refurbishments/replacements, and synchronous condensing conversions.

Holyrood Units 1 2, and 3 are approximately 41, 40, and 31 years of age respectively. However, given their historical seasonal based, lightly loaded service, the operational age for the majority of its equipment and systems is more like 20, 19, and 16 years, respectively. The plant has been well managed and maintained. The units have also seen minimum service at either their maximum continuous rating (let alone over-pressure/over-temperature) or at extreme minimum load. The units tend to operate between 70 and 140 MW (40% and 80% load) and most often around 110 to 125 MW (65-70%). Unit 3 has seen modest synchronous condensing operation since its retrofit in 1986.

As mentioned previously, Units 1 and 2 were uprated from 150 to 175 MW in 1987. The components that were modified or replaced during the unit upgrade have a longer life as compared to the original equipment. These support a longer life expectation for the station as a whole.

The boiler and its major elements were one of the plant's major reliability and life issues. The original high sulphur (2.5%) and high vanadium fuel oil caused significant corrosion and fouling problems that led to upgrades to some of the boiler heat transfer surfaces. In 2009, the change to a higher quality, lower sulphur (0.7%) fuel oil has significantly improved boiler reliability and efficiency and is expected to have a positive impact on the life of boiler systems.

As indicated above, there is no reason why the plant cannot continue to generate electricity reliably to the year 2020 as identified. Similarly, if and when Units 1 and 2 are converted to synchronous condensers (current plan is conversion in 2014) to provide system support, the units and the plant should be able to fulfill that role to 2041. There are several pre-requisites to this, including continued and enhanced inspection and maintenance programs, planned major equipment refurbishment such as generator stator and rotor rewinds, controls and alarms upgrades, and switchgear and breaker refurbishments and replacements.

A key to extending plant life will be the generators, transformers, and switchgear. Units 1, 2, and 3 have major generator inspections scheduled for 2012, 2014, and 2016 respectively. They also have reliability issues that may require a near term need for stator and/or rotor rewinds and possibly later in their life core

or rotor replacement. Transformers are at the point in their lifecycle where significant degradation also occurs. More frequent or continuous monitoring of their condition is required to forewarn of any problems arising. Existing switchgear is in many cases at or near end of life and refurbishment and replacement is required.

Several other key issues with single contingency systems, given age and failure history also raise red flags and include:

- The single contingency failure risk of the fresh/raw water supply from Quarry Brook Pond;
- The single contingency failure risk of the clarifier failure, at least until 2020; and
- The 42 year age and condition of the black start gas turbine – reliability, parts obsolescence make a detailed evaluation critical; especially as the island interconnected system has indicated a potential need for it as an emergency power source.

The black start gas turbine generator and its balance of plant is in need of a major overhaul, as well as refurbishment and replacement of its stack and air intake systems. In addition, it is likely that its fuel receiving and feeding system will need a major overhaul as soon as practical within the next two years.

If Hydro addresses the key issues and maintains a vigorous maintenance and inspection program, there is no technical reason that the plant cannot reach its 2020 generation end of life and 2041 synchronous condensing end of life targets.

**Phase 2 Condition Assessments (Level 2 Inspections)**

Following the Condition Assessment process (detailed in Section 3 of the report), AMEC identified several areas of the plant that had inadequate available information to develop a reasonable, definitive position on whether those areas/equipment could reach their desired end of life or where decisions on run or repair/replace could be taken with certainty. These areas under the Condition Assessment process should undergo a Level 2 inspection.

A summary of the recommended Level 2 inspections and their costs are presented in Section 12 of the report. More details are provided for specific units and systems/equipment in Sections 8 to 11 of the body of the report. It should be noted that the costs include the costs for the enhanced inspection/overhauls for the steam turbine and generator for Units 1, 2, and 3 in 2012, 2014, and 2016 respectively. The priorities (identified as Priority 1 through 4, with 1 being the highest) are somewhat subjective, based on the experience and expertise of AMEC staff.

Table ES-1 is a summary of Level 2 costs by priorities by year.

**TABLE ES -1 LEVEL 2 ACTIVITIES SUMMARY BY PRIORITY LEVEL BY YEAR**

| | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Priority 1 | $17,547 | $392 | $1,600 | $4,615 | $44 | $6,195 | $13 | $4,687 | $0 |
| Priority 2 | $4,811 | $0 | $773 | $1,879 | $1,929 | $229 | $0 | $0 | $0 |
| Priority 3 | $222 | $0 | $217 | $0 | $0 | $5 | $0 | $0 | $0 |
| Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $392 | $2,590 | $6,494 | $1,973 | $6,429 | $13 | $4,687 | $0 |

Table ES-2 is a summary of Level 2 costs by priority level by year for the major plant areas. These plant areas are broken down into synchronous condensing required plant equipment (Synch Cond); steam turbine and auxiliaries (Stm Turb) plant equipment required only for electricity generation; boiler and auxiliaries (Blr Stm) plant equipment required only for electricity generation; switchyard and transformer (Switchy & TS) equipment required for both synchronous condensing and electricity generation; and black start gas turbine and auxiliaries (GTG) equipment and facilities.

**TABLE ES-2 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY BY PLANT AREA BY PRIORITY AND YEAR**

| | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Synch Cond Priority 1 | $7,894 | $73 | $1,494 | $2,286 | $0 | $1,961 | $0 | $2,081 | $0 |
| Synch Cond Priority 2 | $594 | $0 | $594 | $0 | $0 | $0 | $0 | $0 | $0 |
| Synch Cond Priority 3 | $207 | $0 | $202 | $0 | $0 | $5 | $0 | $0 | $0 |
| Synch Cond Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 1 | $7,463 | $0 | $100 | $2,311 | $0 | $2,451 | $0 | $2,601 | $0 |
| Stm Turb Priority 2 | $147 | $0 | $147 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 3 | $15 | $0 | $15 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 1 | $1,758 | $0 | $0 | $0 | $0 | $1,758 | $0 | $0 | $0 |
| Blr Stm Prioirity 2 | $4,070 | $0 | $33 | $1,879 | $1,929 | $229 | $0 | $0 | $0 |
| Blr Stm Prioirity 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 1 | $228 | $116 | $6 | $18 | $44 | $25 | $13 | $6 | $0 |
| Switchy & TS Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 1 | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $392 | $2,590 | $6,494 | $1,973 | $6,429 | $13 | $4,687 | $0 |

**Conclusions & Recommendations**

The study conclusions and recommendations are summarized in Section 14 and Section 15 of the report respectively. They are organized into:

Overall and Station Wide

Site Conditions

Common Facilities

Unit 1

Unit 2

Unit 3

Black Start Gas Turbine

Switchyard

Facility Management

Sections 14 and 15 should be referred to for this information.

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# GLOSSARY

| | |
|---|---|
| °F or oF | Degree Fahrenheit |
| °C or oC | Degree Celsius |
| BTU | British Thermal Unit |
| CO2 | Carbon dioxide |
| CRO | Control Room Operator |
| CRO1 | Control Room Operator Unit 1 (or 2 or 3) |
| CW | Circulating or cooling water |
| Gen | Generator (Only) |
| H2 or $H_2$ | Hydrogen |
| HP | High Pressure |
| kV | Kilovolt |
| kVAR | Kilovolt ampere reactive |
| kW | Kilowatt |
| kWh | Kilowatthour |
| LP | Low pressure |
| Max | Maximum |
| MCC | Motor control centre |
| MCR | Maximum continuous rating |
| mm | Millimetres |
| Mg | Megagrams |
| mg | Milligrams |
| MOT | Main output transformer |
| MVA | Megavoltampere |
| MVAR | Megavolt ampere reactive |
| MW/MWg/MWn | Megawatt /megawatt gross/megawatt net |
| MWh/MWhg/MWhn | Megawatt hour/ megawatthour gross megawatthour net |
| Min | Minute |
| O2 or $O_2$ | Oxygen |
| psig or $psi_g$ | Pound per hour pounds per square inch gauge |
| psia or $psi_a$ | Pounds per square inch absolute |
| ppmvd or $ppm_{vd}$ | Parts per million (dry volume basis) |
| % | Percentage |
| rpm | Revolutions per minute |
| SC | Synchronous condenser |
| scfh | Standard cubic feet per hour |
| SCO | Shift control operator |
| SH | Super heat |
| ST | Steam turbine |
| STG | Steam turbine generator |
| T7 | Transformer #7 |
| TGS | Thermal generating station |
| TWh | Terawatthours (1,000,000 MWh) |
| VAR | Vars |
| V | Volts |
| W | “Warm” start |
| WO | Work order |
| WTP | Water treatment plant |
| yds | Yards |
| Yr (or a) | Year |

# HOLYROOD THERMAL GENERATING STATION
# CONDITION ASSESSMENT AND LIFE EXTENSION STUDY

## 1 INTRODUCTION

### 1.1 General Description of Holyrood Thermal Generating Station

Holyrood Thermal Generating Station (Holyrood) is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

**Units 1 and 2**

Units 1 and 2 were built in the late 1960's as #6 fuel oil fired 150 MW units. Unit 1 entered service in September 1970 and Unit 2 in April 1971. These two units were modified in 1987 to increase their capacity to 175 MW.

**Furnaces/Boilers:** Units 1 and 2 are equipped with Combustion Engineering (now Alstom) tangentially fired natural circulation boilers. The boilers have twelve burners, four on each of three levels, designed to fire a 2.5% sulphur residual crude oil. In January 2009, Holyrood's fuel was changed to a 0.7% sulphur oil to reduce sulphur dioxide emissions, as well as particulate and sulphur trioxide.

The units are neither equipped with low NOx burners nor Overfire air for low NOx operations, nor any particulate capture devices. They were originally equipped with flue gas recirculation for reheat temperature control which was removed early in their service. The furnace is a pressurized furnace design with a forced draft fan, but no induced draft fan. As a consequence, in recent years, considerable effort has gone into assuring minimal furnace leakage into the plant.

The Units 1 and 2 boilers each has two x 50% forced draft (FD) fans driven by 4.16 kV induction motors. And two x 50% Lungstrum regenerative rotary air preheaters. The fan ducts are interconnected downstream of their outlet dampers and upstream of the air preheaters to allow single fan use, and also downstream of the air preheaters.

Upstream of the Lungstrum air preheaters, there are two steam coil air heaters. They are controlled to maintain the cold end metal temperature of the air preheater above the acid dewpoint temperature to reduce corrosion and plugging. They are typically designed to enable suitable operation down to -5 °C (20 °F) at 70% MCR.

**Steam Turbine Generators:** The Unit 1 and 2 steam turbine generators are General Electric (GE) three cylinder HP/IP/double flow LP 3600 rpm tandem compound turbines with GE hydrogen cooled generators. The units were modified by GE in 1987 to increase their capability to 175 MW. The HP turbines' throttle pressure was increased to 13.1 MPa at a superheat temperature of 538 °C. Units 1 and 2 turbines are somewhat unique in that they are not equipped with a main turbine shaft driven oil pump

but have chain driven turning gear motors in the front of the unit, which in recent years have had some reliability issues.

The GE hydrogen cooled generator feeds its own unit exciter transformer which powers a DC static exciter. The exciter supplies a DC field voltage through a carbon brushgear slip ring assembly located on the outboard end of the generator. The normal hydrogen gas pressure in the generator casing is 310 kPa.

**Condensers**: The condenser is a Foster Wheeler design with 1842 $m^2$ (65,025 $ft^2$) of surface area. It is serviced by two x 100% duty vacuum pumps to maintain a 3.4 kPa (1" hg) pressure at maximum continuous rating (MCR).

**Cooling Water System:** The cooling water (CW) system feeding the condenser for each unit receives seawater cooling from two x 50% cooling water pump systems located in the Stage 1 pumphouse. Each pump can provide approximately 2250 L/s (35,700 USGPM) depending on tide) or about 3785 L/s (60,000 USGPM) operating together. Prior to entry into the CW pumps, water flows through two X 100% 1893 L/s (30,000 USGPM) Link Belt double entry traveling screens. The travelling screens function to remove debris from the cooling water prior to entering the pump system.

**Feedwater System:** The feedwater system for each unit consists of six stages of feedwater heating, a reserve feedwater storage tank system, and two feedwater pumps. The six stages of feedwater heating includes two low pressure (LP) heaters, one deaerator feedwater heater and three high pressure (HP) heaters after the feedwater pump.

**Deaerator and HP Feedwater System:** The deaerator for each unit is in effect an LP heater. It includes a deaerator storage tank of approximately 81,650 kg (180,000 lbs) – enough water to supply the boiler feed pumps for about 10 minutes at MCR. The elevation of the deaerator is designed to provide the necessary net positive suction head (NPSH) for the boiler feedwater pumps. Two x 50% boiler feedwater pumps are provided and either can operate and maintain up to a 90 MW load on the unit. They are double case, horizontal construction pumps rated at 75 L/s (1185 USPGM) at a head of 1829 m (6000 ft). Each pump is driven by a 3550 rpm, 3000 HP 4.16 kV, three-phase induction motor. There is no variable frequency drive (VFD) or fluid coupling as is common at other larger units. The three HP feedwater heaters (HP4, HP5, and HP6) are used to raise the feedwater temperature to the necessary economizer inlet temperature. There is no redundancy. HP 4 and HP5 must be bypassed as a set (for example in the event of a high condensate level trip). HP6 can be bypassed individually if necessary.

**Condensate System:** The condensate system for each unit consists of two x 100% condensate extraction pumps to remove condensate from the condenser, a gland steam condenser and one 100% flow condensate polishing system. The condensate extraction pump is a vertical canister pump that circulates condensate water through the gland steam condensers, the LP heaters, and then into the deaerator. The pumps are controlled to keep approximately 56 cm (22 inches) of water in the hotwell (approximately 33,566 kg or 74,000 lbs). The hotwell control, in parallel with the reserve storage tanks, manages variations in feedwater flow. The reserve feedwater storage tank system is designed to provide for surge and emergency requirements and consists of one high level tank and one low level tank, including a second high level tank originally intended for Unit 4, as well as associated piping, transfer pumps, and valving. Each tank has a capacity of approximately 90,850 L (24,000 USG). The transfer pumps have a capacity of 18.9 L/s (300 USGPM) at a head of 105 m (345 ft) and can transfer water between units and can also be used for boiler filling and washing.

**Unit 3**

Unit 3 is a 150 MW unit and was built in 1979 and came online in February 1980.

**Furnace/Boiler:** Unit 3 has a #6 fuel oil fired Babcock and Wilcox front wall-fired, natural circulation boiler. It has nine burners on three levels. It was designed to produce about 135 kg/s (1,072,000 lbs/hour) of steam at 13,030 kPa (1890 psig) at a superheated temperature of 541.6 °C (1005+/-10 °F), and 125.1 kg/s (993,000 Ls/hr) of reheat steam at 3716 kPa (539 psig), 541.6 °C (1005 °F).

The unit is neither equipped with low NOx burners nor Overfire air for low NOx operations, nor any particulate capture devices. The furnace is a pressurized furnace design with a forced draft fan, but no induced draft fan. As a consequence, in recent years, considerable effort has gone into assuring minimal furnace leakage into the plant.

The boiler has two x 50% forced draft (FD) fans driven by 1500 HP, 4.16 kV induction motors. Each FD fan servicing Unit 3 produces about 139.5 $m^3$/s (295,200 ACFM) at 8.8 kPa (35.23" w.g.) at 35 °C (95 °F). It has two x 50% Lungstrum regenerative rotary air preheaters. The fan ducts are interconnected downstream of their outlet dampers and upstream of the air preheaters to allow single fan use, and also downstream of the air preheaters.

Upstream of the Lungstrum air preheaters, there are two steam coil air heaters. They are controlled to maintain the cold end metal temperature of the air preheater above the acid dewpoint temperature to reduce corrosion and plugging. They are typically designed to enable suitable operation down to -5 °C (20 °F) at 70% MCR.

**Steam Turbine Generator:** The Unit 3 steam turbine generator is a Hitachi three cylinder HP/IP double flow LP 3600 rpm tandem compound turbine and a Hitachi hydrogen cooled generator. Unit 3 HP throttle pressure is 12.4 MPa at a superheated temperature of 538 °C. Its main steam flow is rated at 121 kg/s (960,644 lbs/hr) and up to 135 kg/s (1,072,000 lbs/hr) at valves wide open (VWO).

The Unit 3 turbine generator, unlike Units 1 and 2, has an internal shaft driven oil pump in the front standard, which supplies lubricating oil to the bearings, power oil (relay oil) to drive the east and west main steam stop valves, the control valves, and the east and west combined reheat intercept stop valves and other various valves associated with the unit.

**Condensers:** The condenser is a Foster Wheeler design with 1842 $m^2$ (65,025 $ft^2$) of surface area. It is serviced by two x 100% duty vacuum pumps to maintain a pressure of 3.4 kPa (1 inch hg) at MCR.

**Cooling Water System:** The cooling water system feeding the condenser receives seawater from two x 50% cooling water pump systems located in the Stage 2 Pumphouse. Each pump can provide approximately 2250 L/s (35,700 USGPM depending on tide) or about 3,785 L/s (60,000 USGPM) operating together. Prior to entry into the CW pumps, water flows through two X 100%, 1893 L/s (30,000 USGPM) Link Belt double entry traveling screens. The travelling screens function to remove debris from the cooling water prior to entering the pump system.

**Feedwater System:** The feedwater system consists of six stages of feedwater heating, a reserve feedwater storage tank system, and two feedwater pumps. The six stages of feedwater heating include two LP heaters, one deaerator feedwater heater and three HP heaters after the feedwater pump.

**Deaerator and HP Feedwater System:** The deaerator is in effect an LP heater. It includes a deaerator storage tank of approximately 81650 kg (180,000 lbs) – enough water to supply the boiler feed pumps for about 10 minutes at MCR. The elevation of the deaerator is designed to provide the necessary NPSH for

the boiler feedwater pumps. Two x 50% boiler feedwater pumps are provided and either can run to maintain up to 90 MW load on the unit. They are double case, horizontal construction pumps rated at 75 L/s (1185 USPGM) at a head of 1829 m (6000 ft). Each is driven by a 3550 rpm, 3000 HP, 4.16 kV, 3 phase induction motor. There is no VFD or fluid coupling, as is common at other larger units. Three HP feedwater heaters (HP4, HP5, and HP6) are used to raise the feedwater temperature to the necessary economizer inlet temperature. There is no redundancy. HP 4 and HP5 must be bypassed as a set (for example in the event of a high condensate level trip). HP6 can be bypassed individually if necessary.

**Condensate System:** The condensate system consists of two x 100% condensate extraction pumps to remove boiler water from the condenser, a gland steam condenser, and one 100% flow condensate polishing system. The condensate extraction pump is a vertical canister pump which circulates condenser water through the gland steam condensers, the LP heaters, and into the deaerator. The pumps are controlled to keep approximately 56 cm (22 inches) of water in the hotwell (about 33,566 kg or 74,000 lbs). The hotwell control, in parallel with the reserve storage tanks, manages variations in feedwater flow. The reserve feedwater storage tank system is designed to provide for surge and emergency requirements and consists of one high level tank and one low level tank. It also includes a second high level tank, originally intended for Unit 4, as well as associated piping, transfer pumps, and valving. Each tank has a capacity of approximately 90,850 L (24,000 USG). The transfer pumps can transfer water between units and can be used for boiler filling and boiler washing. The pumps can provide up to 18.9 L/s (300 USGPM) at a head of 105 m (345 ft).

**Fuel Oil Storage & Delivery**

Fuel oil is delivered by tanker to the unloading docks and from there is delivered by an electrically heat traced pipeline to the fuel oil storage tank farm. The tank farm consists of four 33,710 $m^3$ (212,000 USG) tanks. Each tank has two suction heaters for temperature control of the oil discharge, as well as two immersion heaters that are supplied by auxiliary steam. Condensate is discharged via steam traps to a drainage system. From the tank farm, the fuel oil supplies a day tank located on the northeast side of the powerhouse via an 18 inch steam heat traced supply header by gravity flow.

The heavy oil day tank was replaced when Unit 3 was installed. The tank provides gravity flow to the supply pumps on each individual unit. For example, Unit 3 has a maximum flowrate requirement of 10.08 kg/s (80,000 lb/hr) supplied by two x 100% positive displacement pumps through two x 100% fuel oil steam heaters providing 99 °C (210 °F) oil to the units. If required, there is a bypass around the day tank from the main tank farm.

A light oil system is used for the initial start-up of the boilers during a cold start when atomizing steam is not available for firing with #6 oil. The oil system consists of storage tanks that are connected to two X 100% positive displacement pumps via a header complete with a recirculation system back to the tanks from the burner front header. The pumps have a discharge pressure of approximately 1034 kPa (150 psi). During start-up, light oil is fired into the boilers in the bottom level of burners. Atomizing air is provided for burner firing and for burner purging during boiler shutdown.

**Compressed Air:** Compressed air systems are provided for both Stage 1 and Stage 2. The air compressors for Stage 1 have been replaced, but the service air pressure vessels and instrument air pressure vessels are original equipment and are scheduled for replacement. Stage 2 originally had two X two-stage water cooled rotary screw Atlas Copco compressors providing compressed air to the service air system. A new replacement VFD air compressor was installed in 2008. A portion of compressed air is extracted from the service air receivers and is then filtered and dried for use as instrument air. Cooling water is provided from the general service water system for the cooler and aftercooler requirements for the air compressors.

## Gas Turbines

The gas turbine generator system serves as a black start unit for the station and is occasionally used for system support.

As the power source for the 13.5 MW packaged generating unit, the gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine used by Associated Electrical Industries (AEI) of Manchester, England. Manufacture of this type of generating unit commenced in the mid 1960's.

The unit was supplied to the Newfoundland and Labrador Power Commission in 1966 and was considered to be a development model. The generator unit itself is comprised of a number of components: inlet plenum, AVON 1533-70L power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system. It receives ambient air from the inlet plenum. To significantly boost the air pressure, this air is compressed via a 17- stage axial flow compressor in the forward section of the AVON 1533-70L. Fuel is supplied to an eight burner combustion section to facilitate a rapid increase in the temperature and velocity of the axial air flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir.

The unit has had significant overhauls/repairs in 1978, 1986, 1991, and 2007.

## Buildings

Main Buildings: The main buildings on site are:

- Main Powerhouse (Boiler House, Steam Turbine Hall, Administration Building, Water Treatment Plant)
- Waste Water Treatment Process Building
- Waste Water Treatment Basin Building
- Stage 1 Pumphouse Building
- Stage 2 Pumphouse Building

These are generally steel clad buildings with concrete foundations. The powerhouse roofing is primarily flat asphalt roofing with some clad steel roofs on some of the administration and water treatment parts. The other buildings have insulated, steel clad roofing.

**Peripheral Buildings:** The peripheral buildings include the following smaller buildings:

- Training Centre
- Guardhouse
- H2 and CO2 Storage Building
- Shawmont building
- Main Warehouse
- Pipe Shop
- Emergency Response Building
- Gas Turbine Building
- Chemical Storage Building

The buildings are either pre-engineered steel buildings or traditional steel buildings sitting on concrete foundations.

**Powerhouse Heating and Ventilation:** Steam type unit heaters are provided throughout the building, as well as access door heaters. For Stage 1, there are 69 operational unit heaters (including door heaters). For Stage 2, there are 25 unit heaters and five door heaters. Unit heaters are typically 19,870 kJ/min (1,130,000 BTU/hr) and door heaters typically 19,870 kJ/min (1,130,000 BTU/hr).

Combustion air requirements are drawn through the FD fan intake ducts which can draw air from either inside or outside of the powerhouse, depending on the outdoor temperature. The powerhouse ventilation system is designed to balance the combustion air needs against excessively cold or warm temperatures, drafts, and negative pressures in the powerhouse. For Stage 2, there are two roof vents and six horizontal wall vents.

A warm air make-up system was installed in 1992 in an attempt to ensure that plant pressure and air temperature were maintained at satisfactory levels. It included vent rooms with steam coil heaters on both the north and south walls of the plant. There have been issues with automated control under some circumstances that have resulted in freezing issues with nearby water lines inside the plant. The plant intends to put these systems into a manual control mode.

**Pumphouse Heating and Ventilation:** Twelve steam type unit heaters are provided in the Stage 1 pumphouse (2286 kJ/min – 130,000 BTU/hr) and one door heater. Four steam type unit heaters are provided in the Stage 2 pumphouse and one door heater. The unit heaters are typically 19,870 kJ/min (1,130,000 BTU/hr) and the door heaters 19,870 kJ/min (1,130,000 BTU/hr). The buildings also have roof ventilating fans.

# 2 PROJECT DESCRIPTION & SCOPE

AMEC Americas Limited (AMEC) was contracted by NL Hydro, a NALCOR Energy Company, to conduct Phase 1 of a Condition Assessment and Life Extension Study for the Holyrood Generating Station.

## 2.1 Study Basis

The basis for the study is as follows:

- 2010 to 2015 Generation Life
    1. Annual Capacity Factor (ACF)/pattern: ACF between 30% and 75% until 2015
    2. Reliability: high, similar to current
    3. Condition Assessment and Life Extension Schedule:
        - Phase I -2010
        - Phase 2 – 2011
        - Implementation – 2012 and beyond
- 2015-2020 Generation Standby
    1. Capacity required
    2. Operating pattern likely
    3. Hot/cold standby – time for return to service, and
    4. Reliability/availability of generation
- Synchronous Condensing 2015-2041
    1. Capability (generator, transformers) – similar to Unit 3
    2. Operating pattern and requirements
- Gas Turbine Operation
    1. Capacity required
    2. Operating pattern likely
    3. Reliability/availability of generation
    4. Life: 2020
- Subsequent equipment condition analyses

## 2.2 Study Focus

The study focuses on the following key assets:

1. Generators
2. Switch gear and switchyard
3. Transformers
4. Control system associated with generators
5. Station auxiliary systems
6. Buildings and building M and E system
7. Cooling water system associated with generators
8. Gas turbine generator and diesel gensets
9. Hydrogen and carbon dioxide
10. Compressed air
11. Generator lube oil

Nevertheless the other “Lower Priority Systems/Equipment” addressed include:

1. Fuel Systems (light and heavy oil);
2. Boiler System:
   a. Boilers
   b. Feed water system
   c. Heat exchangers
   d. Condensers
   e. Deaerators
   f. FD fans
   g. Air preheaters
   h. Stacks and breaching
   i. DCS associated with steam systems
   j. Electrical & instrumentation associated with steam systems
3. Turbines
4. Cooling water system associated with steam systems
5. Waste water treatment facility
6. Water treatment system

The study scope excludes consideration of the Holyrood marine terminal.

# 3 METHODOLOGY

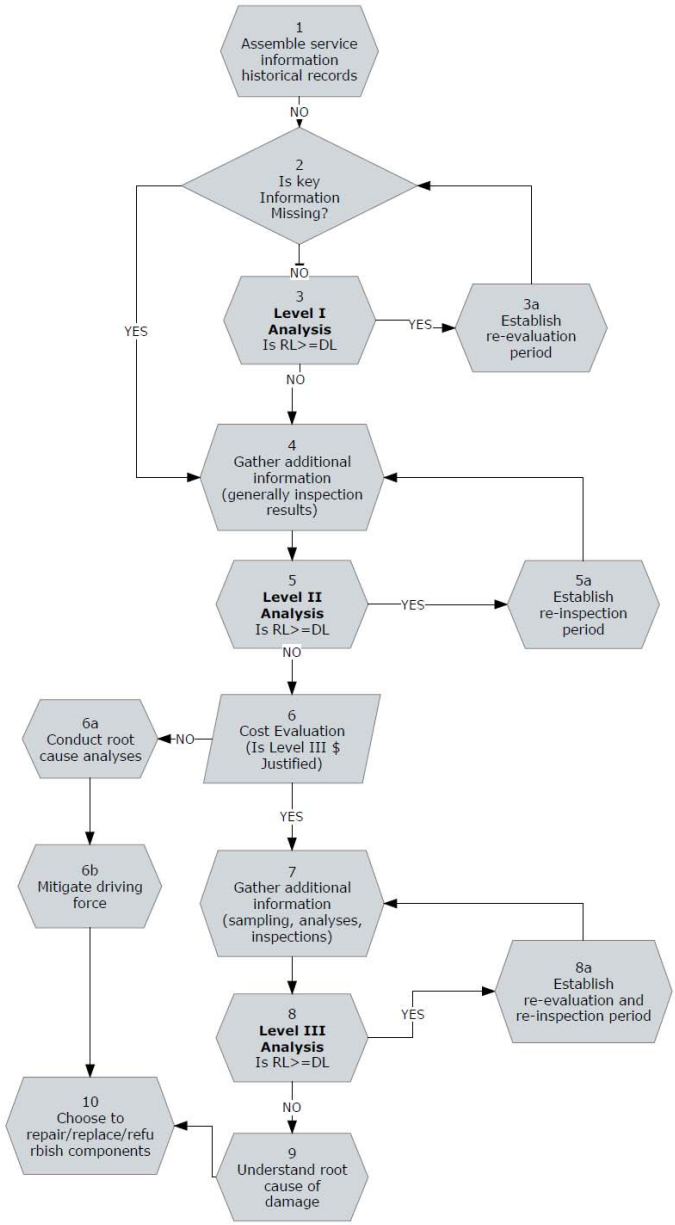
The study methodology included the following steps:

- Initial kick-off meeting and site visit
- Development of Asset Register & Flow Chart
- Site review and equipment/facility inspections
- Review the Holyrood Plant Maintenance Program – review existing information/background data and staff interviews
- Review and analysis of information and data obtained through:
    1. Existing studies on condition assessment, life expectancy, previous studies of life extension, and the associated costs (capital and O & M) of such programs
    2. Previously noted physical inspection reports of equipment
    3. Equipment lost time analysis data
    4. Interviews and discussions with NL Hydro management
    5. Interviews and discussions with Holyrood Operations and Maintenance personnel
    6. Analysis of power demands vs Holyrood generation capabilities
- Analysis of the impact and value of capital upgrades and operational and maintenance improvements
    1. Determination of remaining equipment and facility life – using existing information, experience, and OEM consultations as required to develop life cycle curves for major critical equipment and facilities; and
    2. Conduct equipment risk of failure analysis for major plant components, equipment, systems, and the entire facility. Identify any components or systems that require further investigation; and make recommendations for work that will be required to extend the plant's useful life into the future with the same high degree of reliability as experienced in the past.

To the extent practical, the approach followed the intent of the EPRI Condition Assessment Level 1 process or a reasonable alternative approach as determined by individual technology experts. The basic approach consistent with the EPRI Level 1 approach is:

- Examine only design or overall service parameters
- Compare, using conservative considerations, the residual life to the anticipated extended service period (or the interval to the next inspection whichever is less)
- Incorporate service and measurement information where practical, available and useful including:
    1. Unit running hours
    2. Numbers of starts and stops – hot, warm, cold, trips, ramp rates
    3. Unit load records
    4. Failure history and analyses reports
    5. Maintenance activities
    6. Specifics of past component repairs and replacements
    7. Materials of construction composition checks
    8. Dimensional checks
    9. Steam temperature histories
    10. Design parameters

The generic EPRI condition assessment methodology is illustrated in Figure 3-1. This chart includes step numbers used in the report to identify where in the process various systems and equipment are considered to be.




NOTE: Remaining Life (RL) is the estimated reliable remaining life of a piece of equipment or system based on available inspection and equipment data. Desired Life (DL) is the desired life of the component, but for decision making is the earlier of the desired end of life (EOL) date or the next inspection that can yield date for life assessment purposes.

**FIGURE 3-1 GENERIC EPRI CONDITION ASSESSMENT METHODOLOGY**

For mechanical systems, it considers aspects such as:

| Feature | Level I | Level II | Level III |
|---|---|---|---|
| **Failure History** | Plant records | Plant records | Plant records |
| **Dimensions** | Design or nominal | Measured or nominal | Measured |
| **Condition** | Records or nominal | Inspection | Detailed inspection |
| **Temperature and pressure** | Design or operational | Operational or measured | Measured |
| **Stresses** | Design or operational | Simple calculation | Refined analysis |
| **Material properties** | Minimum | Minimum | Actual material |
| **Material samples required?** | No | No | Yes |
| More rigorous assessment → | | | |
| More accurate operation data required → | | | |
| More accurate estimate of equipment RL → | | | |

**FIGURE 3-2 EPRI METHODOLOGY – INFORMATION REQUIREMENTS**

The Level 1 analysis considers several issues, such as:

- Has the unit component operation exceeded its design parameters (i.e. temperature, pressure) for significant periods of time or by significant amounts?
- Will the required future service requirement exceed significant design parameters (i.e. cycling, two-shifting capacity) without suitable modification?
- Has unit maintenance and reliability shown that the design philosophy and materials have not been conservative since the units was operational?
- Has the failure history been excessive?

The following figures illustrate some more detailed, specific considerations within the generic approach for high temperature steam headers:

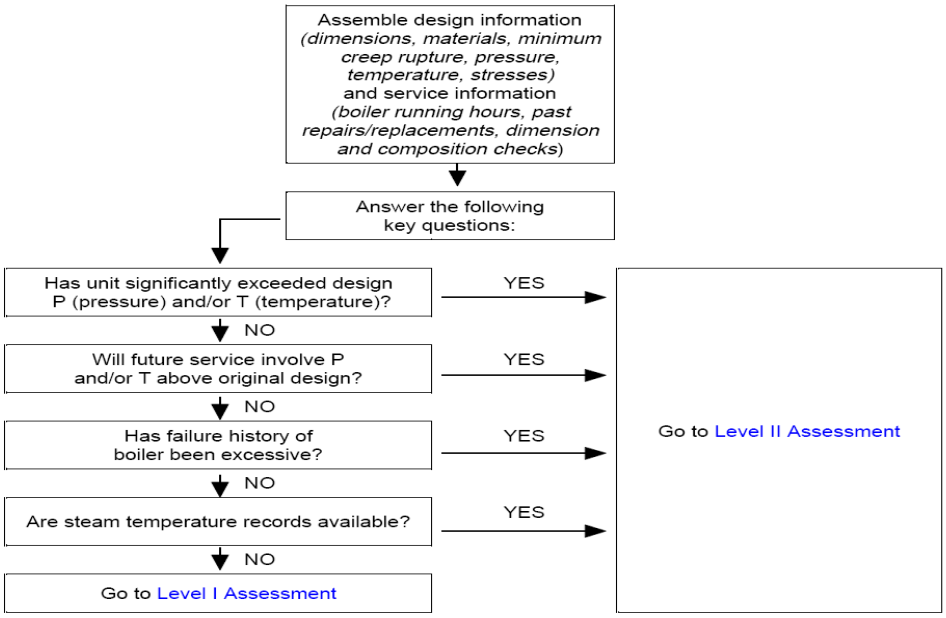



**FIGURE 3-3 GENERAL ROADMAP FOR HIGH TEMPERATURE STEAM HEADERS**

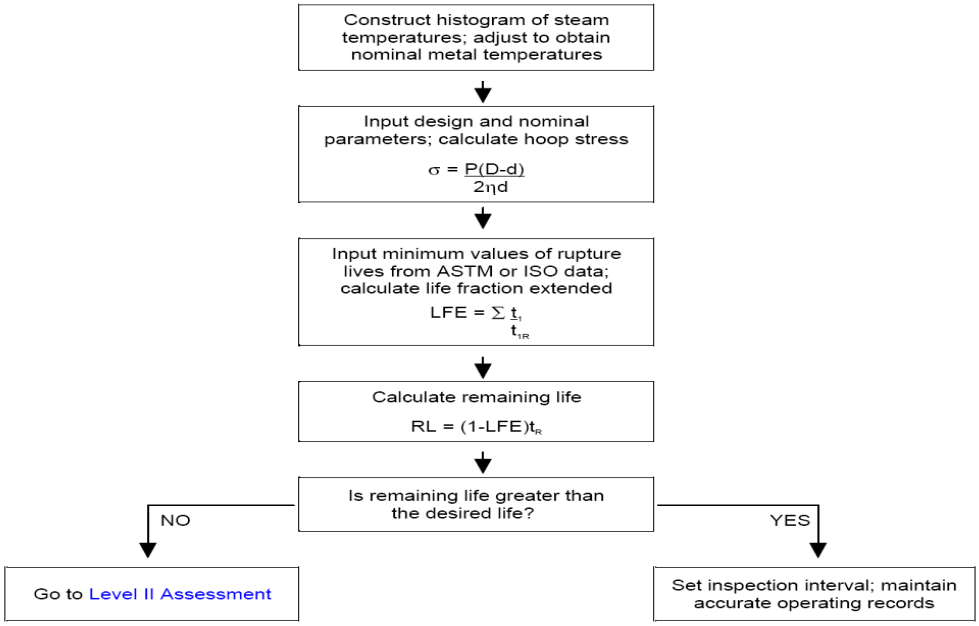



**FIGURE 3-4 LEVEL I ASSESSMENT: HIGH TEMPERATURE HEADERS**

The intent in moving from Level 1 to Level 2 is to address items with insufficient information to make decisions going forward. For example in the chart below, Level 1 allows selection of a number of components to replace, repair or refurbish, but leaves the majority as uncertain.

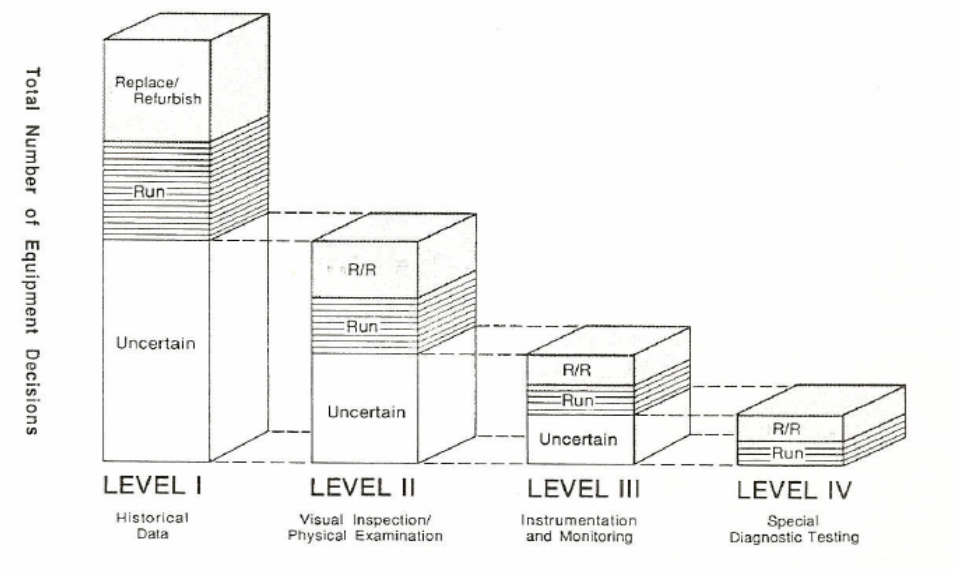



**FIGURE 3-5 FOUR-LEVEL ELECTRICAL COMPONENT LIFE ASSESSMENT**

For electrical systems, the same basic steps as the generic flowsheet in Figure 3-1 are used for this study. Figure 3-6 presents a more detailed perspective of the considerations in the process.

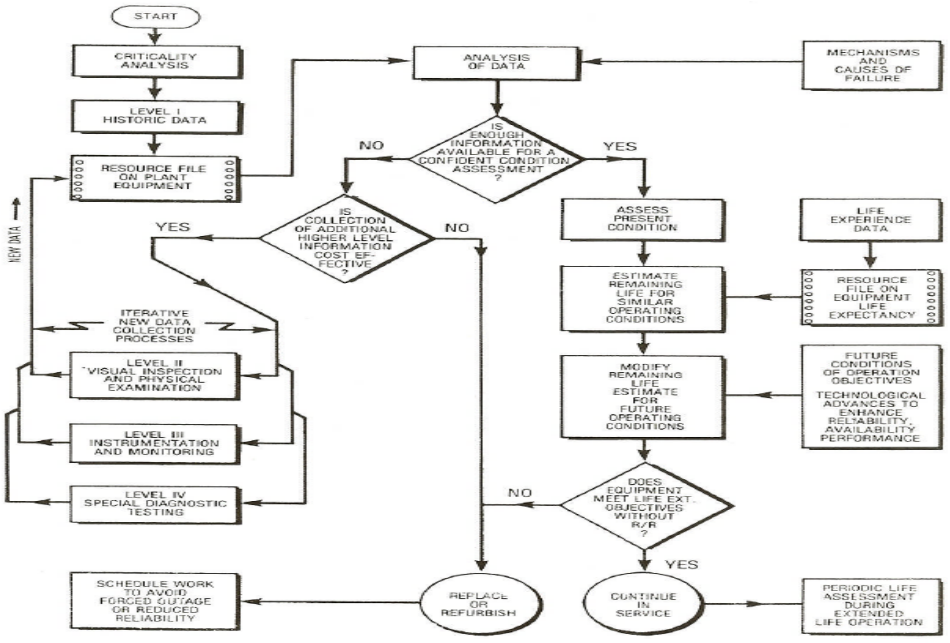



**FIGURE 3-6 GENERAL LIFE ASSESSMENT PROCESS: ELECTRICAL EQUIPMENT**

## 3.1 Background Information and Studies

The key background information and studies included the following:

- Identification of key equipment;
- Identification of recent improvements/changes – fuel, major modifications, etc.;
- Vendor consultation;
- Current/planned station budgets and plans;
- Timing of changes – likelihood;
- Staffing, Operating, Maintenance and Administration (OMA) plans;
- Criteria for operation and operating parameters;
- Major equipment to be considered;
- Present design and operating data – e.g. temperatures, vibration data, cooling water and oil temperatures, etc. at typical load points;
- Facility drawings as required, preferably on CAD;
- Maintenance data for each major piece of equipment, especially from the last major maintenance outage. Details of known limitations, and operating concerns; and
- Details of major repairs performed on major equipment.

## 3.2 Field Investigation

It was agreed that the scope and results of field investigative work, analyses undertaken, variables examined, and operational considerations would address:

- Station operating hrs and cold/warm/hot starts by unit and year since start up
- Station operating hrs and cold/warm/hot starts by unit and month from January 2007 to present
- Major station outages and associated reports (planned, major maintenance) by unit particularly those since 2000
- Major plant equipment and system changes (i.e. major fuel change, equipment change-out, major boiler upgrades, steam turbine modifications and generator modifications) since in-service (particularly in last 10 years) including the scope and timing of the changes
- Major inspections (and associated reports) on key equipment and systems since 1997 – including timing of the inspections and scope
- Unit performance – capacity, heat rate, availability since 2000
- Current budget and business plan information details
- Occurrences where the actual operating conditions exceeded the equipment design conditions including:
    1. High pressure and temperature steam and/or water
    2. Superheat and reheat steam systems
    3. Boiler feedwater and boiler tube systems
    4. Steam turbine components
    5. Higher than design flue gas temperatures (associated with boiler systems)
    6. Vibration
    7. Hydrogen pressure or temperature (in generator)

A list of the initial documentation provided by NL Hydro is presented in Appendix 1.

## 3.3 Scope, Key Features and Parameters of Study

The study scope was discussed with NL Hydro during an initial kick-off meeting and it was agreed that:

- AMEC would use the Holyrood asset register as the primary index, highlighting the equipment and systems that would be addressed and the level to which they would be assessed. The green areas indicate the equipment and systems that would be addressed and the level of the assessment – i.e. system, sub-system, and equipment. The marked up list is attached as Appendix 1.
- The generic EPRI Condition Assessment approach illustrated in Figure 3-1 is the methodology employed. The boiler analyses followed the specific approach in Figures 3-3 and 3-4 for high temperature headers. The more generic approach, using industry and individual expert experience, taking into account Holyrood specific information, was applied in most other cases.
- The intent is to provide an assessment of Level 2 requirements including schedule and cost. Given the stage of and eventual scope of the work, as well as the economic environment, an accuracy of +/-10-15% is a target at best, typically achieved during detailed quotes on actual work, and the overall costs are practically speaking more of a +10/-25% quality, typical of this stage of the work.

The following key features of the study were identified:

- No new detailed information was to be developed. The assessment was to be based on existing information obtained through existing documents and studies, plant interviews, and readily undertaken visual inspections (walk-downs).
- The findings of existing studies, even to the extent of MCC findings of obsolescence should be taken into account.
- The timing of planned equipment inspections and overhauls should be taken into account. The intent of the EPRI Level 1 methodology is to determine whether a piece of equipment or system can either reach its intended planned life or reach its next major inspection and overhaul. If it is determined that the equipment cannot reach its planned life or next major inspection/overall, then a Level 2 condition assessment is necessary.
- The study will focus primarily on key equipment systems required for synchronous condensing operation up to 2041, beyond the generation plans for 2010 to 2020.

## 3.4 Cost Estimating and Schedule - Phase 2 of a Condition Assessment Program

In considering the requirements for a Phase 2 study that includes a Level 2 Condition Assessment, it was agreed that AMEC would provide a cost estimate and schedule to complete a Phase 2 study, including quarterly cost and cash flows for 2011.

The Phase 2 study plan would include the assumptions made and basis used for preparation of the cost estimate. Where practical, the cost estimate will target an accuracy range of +/- 10%. It was identified and agreed that this would not be practical in many cases given the stage of work and the labour and materials marketplace and any key considerations pertinent to completing Phase 2 of a condition assessment program relating to the cost estimate and schedule provided. A fairly conservative approach was taken such that the overall costs are practically speaking of a +10/-25% quality, typical of this stage of the work.

## 3.5 Site Visits

AMEC staff visited Holyrood several times from January through May of 2010. These included:

- Two one-week visits by Ian Leach and Blair Seckington in January and May 2010;
- A one-week visit by three members of AMEC Nuclear Safety Solutions (NSS) in February 2010 and an additional one week visit by a single member of NSS in March 2010;
- A one-week visit by Blair Seckington in April 2010 to address balance of plant issues and project updates; and
- Several day visits by AMEC St John's staff to address civil, structural, gas turbine, and balance of plant issues between January and May 2010

In the course of these visits, meetings and interviews included the following staff:

- Plant management team as a whole – kick-off, scope, areas of responsibility, general information sharing, and NSS work scope;
- Terry LeDrew (Plant Manager) – key plant issues and asset history;
- Jeff Vincent (Manager-Long Term Asset Planning) – various plant asset conditions, capital plans, Instrumentation and Controls (I&C), Electrical, and organization;
- Wayne Rice (Manager-Work Execution) – various equipment and system conditions and plant staffing;
- Sean Mullowney (Plant Electrical Engineer) – various technical issues and programs regarding electrical systems, instrumentation, and controls;
- Paul Woodford (Maintenance Contracts Engineer) – NDE and test program results;
- Christian Thangasamy (Plant Mechanical Engineer) – various technical issues and programs related to condensers, boilers, synchronous condenser, steam turbine generator, motors, and pumps;
- Mike Flynn (Mechanical Maintenance Supervisor) – crane maintenance and the balance of plant (BOP) systems;
- Mike Manuel (Manager-Environment, Health and Safety) – water treatment plant, performance, plant future as a generating facility, and reliability;
- Ed Finn (Plant Chemist) – water treatment plant, waste water treatment plant, water and steam chemistry conditions, water system, and condensate polishing systems;
- Alonso Pollard (Performance Specialist) – performance data (reliability and availability), condenser performance and modifications, and cooling water pipe conditions;
- Gerard Cochrane (Manager - Operations) – plant and equipment performance issues, plant operations issues, and operational labour issues;
- Plant Shift Supervisors and Operators (various) – plant operations issues and performance;
- Ron LeDrew (Emergency Response Coordinator) – Emergency Response Team (ERT) activities;
- Bob Coish (Retiree, former Holyrood Plant Asset Manager, Co-Lead on Holyrood Asset Maintenance Review) – past major projects, asset conditions, and changes;
- John Adams (Alstom Technical Director) – boiler pressure parts, , air and gas side conditions, information, overhaul , inspection, and design information for Units 1,2, and 3;
- Brandon Berlin (GE Technical Director) - Steam turbine and generator information, condition assessments, overhaul, inspection, and design information for Units 1, 2, and 3;

- Jerry Goulding (Retiree, former Shift Supervisor, Asset Specialist, and Co-Lead on Holyrood Asset Maintenance Review) –past major projects, asset conditions, and changes; and
- Bob Garland – (Asset Specialist) – Controls and condensate polishers.

In addition, the following meetings were held at Hydro Place located in St John's:

**January**

- Project Kick Off;
- Assess base information availability; and
- Clarify project scope

**April**

- Update on project status; and
- Review asset register with respect to equipment status and history

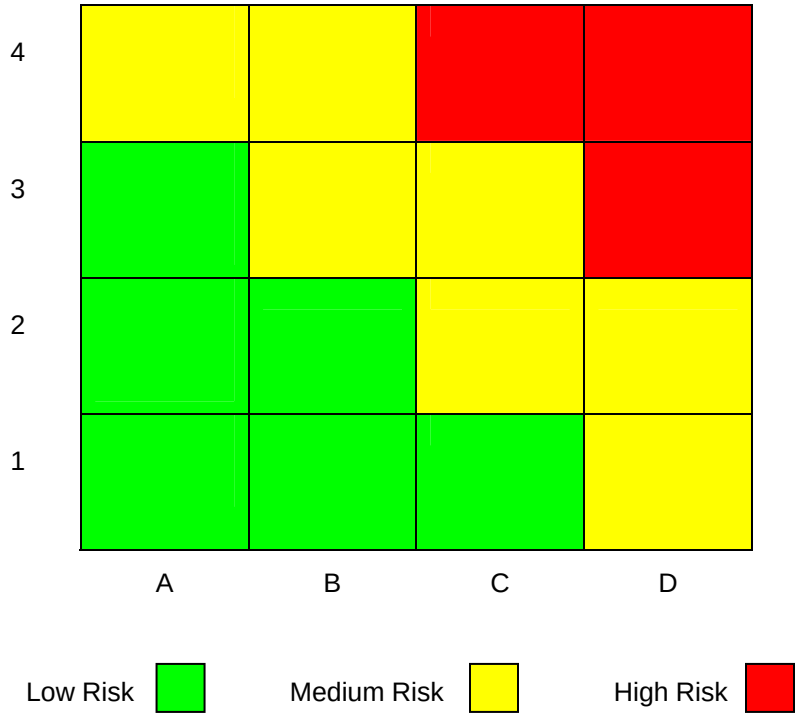
**May**

- Review maintenance history

## 3.6 Technological Risk of Failure Analysis

The risk assessment model has been developed based on methods proposed by the American Petroleum Institute (API RP 580), in lieu of a model specific to the power utility industry. The basic concept consists of a 4 x 4 matrix with the consequence measured in cost terms on the base or horizontal axis and the likelihood or frequency of the event on the vertical axis. The study risk of failure analysis was performed using the model illustrated below in Table 3-1.

**TABLE 3-1 TECHNOLOGICAL RISK OF FAILURE ANALYSIS MODEL**




Likelihood of Failure Event:

1. Greater than 10 years
2. 5 to 10 years
3. 1 to 5 years
4. Immanent (< 1 year)

Consequence of Failure Event:

A. Minor ($10k-$100k or derating/1 day outage)
B. Significant ($100k-$1m or 2-14 days outage)
C. Serious ($1m-$10m or 15-30 days outage)
D. Major (>$10m or >1 month outage)

Actions:

- Items that do not apply are not ranked
- Low Risk: Monitor long term (within 5 years)
- Medium Risk: Investigate and monitor short term. Take action where beneficial
- High Risk: Corrective action required short term

### 3.6.1 Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defense. The modified model is presented below in Table 3-2.

**TABLE 3-2 SAFETY RISK FAILURE ANALYSIS MODEL**

| | | | | |
|---|---|---|---|---|
| 4 | | | | |
| 3 | | | | |
| 2 | | | | |
| 1 | | | | |
| | A | B | C | D |

Low Risk Medium Risk High Risk

Likelihood of Safety Incident Event:

1. Improbable – so that it can be assumed not to occur
2. Unlikely to occur during life of specific item/process
3. Will occur once during life of specific item/process
4. Likely to occur frequently

Consequence of Safety Incident Event:

A. Minor - will not result in injury, or illness
B. Marginal - may cause minor injury, or illness
C. Critical - may cause severe injury, or illness
D. Catastrophic - may cause death

Actions:

- Items that do not apply are not ranked;
- Low Risk: Monitor, take action where beneficial;
- Medium Risk: Investigate and monitor short term. Take action where beneficial; and
- High Risk: Unacceptable. Corrective action required short term

## 3.7 Priority Rating

A numbered priority was assigned to the various “Recommended Actions”, “Level 2 Inspections”, and “Capital Enhancements” throughout Sections 8 to 11 of this report. The scale used was from “1” to “4”. A “1” is the highest priority and essentially means that this activity should definitely be undertaken and where practical in or about the timing identified. A “4” is the lowest priority and essentially means that the item is essentially low risk and low impact and may be much more readily delayed or undertaken in some other fashion. The priority ranking is a subjective relative ranking by AMEC, meant to be an aid to Hydro in allocating resources and assessing trade-offs and program delays.

The priority ranking is not based on a rigorous process, but does take into consideration a number of aspects such as:

1. The impact (likely and worst case) of the item under consideration on achieving the end of life (EOL) goal, on plant operation health and safety, and on environmental and regulatory requirements;
2. The urgency of the need for action on the item under consideration;
3. The degree of certainty of the requirement for the item under consideration;
4. The experience at Holyrood and in the broader industry context with the item;
5. The ability to mitigate or address the issue in other ways;
6. The timing of the recommended response to the item under consideration;
7. The cost of the item under consideration relative to others; and
8. The ability of existing and planned or ongoing actions to address the item in a timely and successful manner.

The priority value of any item should be read in the context of its recommended timing. An item can be a “1”, but be scheduled for a later date if it is deemed that sufficient information exists to be confident of the minimal likely impact of the deferral (usually to tie in with a planned major activity such as an overhaul).

# 4 HOLYROOD ASSET REGISTER

One task of the project was to develop an asset register for the plant.

Initially the plan was to use a system based on the CEA/Monenco/OPG Thermal Subject Index (TSI)/System Classification Index (SCI) that is very plant/system user-friendly and uses the same "asset numbers" with a different prefix for equipment serving the same purpose on similar units and even across stations.

NL Hydro currently has a financial system based asset register for Holyrood. At the direction of NL Hydro, this system was used for the study. It was agreed with the Holyrood Plant Manager which assets would be addressed during the study. These are highlighted in green in Appendix 1.



# 5 HOLYROOD PLANT MAINTENANCE PROGRAM REVIEW

As input to the overall condition assessment and life extension study of the plant, AMEC reviewed the Holyrood plant maintenance program using existing information, background data, and staff interviews. AMEC is aware that the plant preventative maintenance (PM) program is currently undergoing a major review by NLH and is scheduled to be completed by the end of 2010. AMEC is also aware that the plant is currently re-organizing to better define its long term asset management role and its shorter term maintenance role.

The review consisted of observations of the role of the maintenance programs, past and present, as well as a focused review during the week of May 10, 2010. Reviews were undertaken with Wayne Rice, Bob Coish, Jerry Goulding, Jeff Vincent, Todd Collins, as well as several of the plant maintenance and operations staff. The discussions also included the new NL Hydro corporate asset maintenance review strategy.

## 5.1 Maintenance Strategy

The maintenance strategy presently in effect at Holyrood is basically a “Best Practices” approach, implemented through a combination of in-house resources for work performance and/or management. It also includes external resources for major equipment technical support, overhauls, and external contracting for specialized services. It uses the long term asset management and short term maintenance implementation model to ensure that both long term goals and short term needs are both addressed.

From AMEC’s perspective, in most areas of the operation, the maintenance strategy and the asset management program at Holyrood are well implemented and consistent with other thermal generating stations across North America.

### 5.1.1 Maintenance Implementation

As mentioned above, Holyrood maintenance is implemented through a combination of in-house resources for work performance and/or management and external resources for major equipment support, overhauls, and external contracting for specialized services.

For the major critical components such as boilers and boiler auxiliary systems, steam turbines, generators, and auxiliary systems, NL Hydro uses multi-year maintenance contracts. The boiler contract is currently in place with Alstom Power and the steam turbine generator contract is with GE. Under these contracts, the service contractors provide the majority of the boiler, turbine and generator maintenance, including major and/or minor overhauls. Alstom and GE have technical directors on site ensuring that Holyrood’s needs are met.

The plant also has approximately 20 – 25 smaller contracts such as winter snow plowing, garbage and waste disposal, drinking water supply, pressure washing and vacuum truck requirements, etc. Specialized areas such as Non Destructive Evaluations (NDE), high energy pump maintenance, and elevator servicing are also contracted because of the limited number of times these services are normally required.

Maintenance activities on the remainder of the plant are completed by the maintenance department under the direction of the plant’s supervisory staff. If required, technical representatives from either the equipment supplier directly or a qualified representative from contracted technical resource companies will aid in dismantling and rebuilding specific equipment.

The use of contractors and external technical resources ensures consistent quality and efficient utilization of maintenance budgets. It is extremely difficult and expensive to maintain every specialized skill set required within a thermal generating station and the use of external resources is cost effective.

## 5.2 Staffing

Figure 5-1 below provides an overview of the basic plant staffing configuration as of August 2010.

The long term asset planning department is responsible for monitoring and updating the 20 year plan, asset register, critical spares database, maintenance programs, and capital program. The department consists of the engineering support staff as shown in the Figure 5-1. The work execution department is - well organized and in line with conventional disciplines. The department includes:

- Mechanical Maintenance – 21 positions
- Electrical Maintenance – 6 positions
- Instrumentation & Control Maintenance – 7 positions
- Planning – 4 positions

The operations department consists of a manager, operations specialist, performance specialist, and thirty six operations support staff.

The safety, health, and environment department consists of a manager, safety coordinator, environmental technologist, chemical technologists, and emergency response technicians.

The plant support services department consists of a team lead, three administrative staff, and four warehouse staff to support all plant departments.

In 2010, AMEC compared the staffing requirements of the six x 150 MW Burrard Thermal Generating Station (TGS) (BC Hydro, seasonal peaking station) against the Lennox TGS (four x 500 MW oil and gas fired station) located in Ontario (OPG, peaking station) and the two x 175 MW and one x 150 MW oil fired Holyrood TGS (NL Hydro, seasonal capacity and base/intermediate). The details of the comparison are illustrated below in Table 5-1.

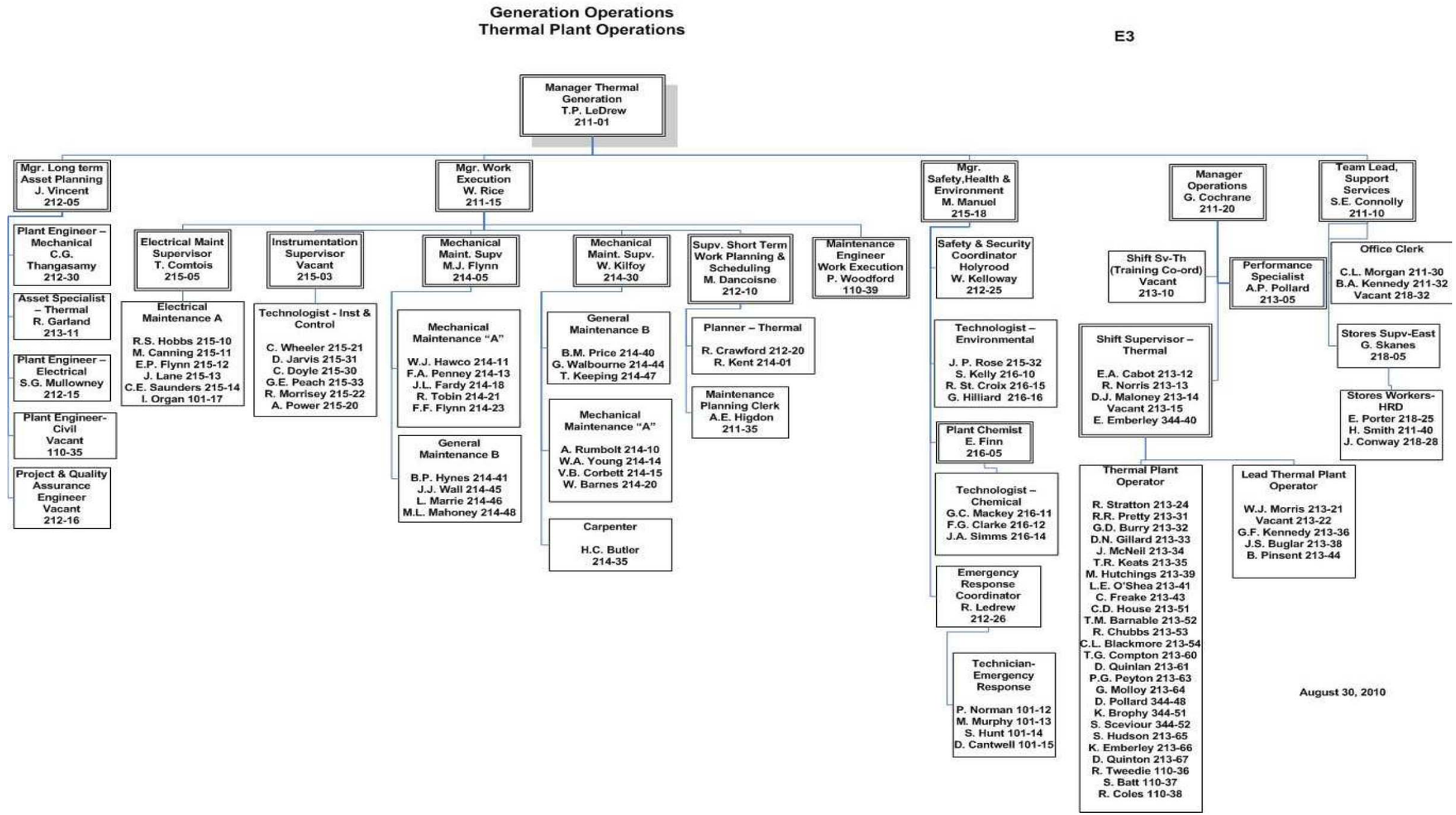



**FIGURE 5-1 BASIC STAFFING CONFIGURATION – AUGUST 2010**

**TABLE 5-1 STAFF COMPARISON TABLE BETWEEN BURRARD TGS/HOLYROOD/LENNOX GS**

| Station | Burrard 6 x 150 MW | Holyrood 2x 175, 1 x 150 MW | Lennox 4 x 500 MW |
|---|---|---|---|
| **Position** | Plan Scenario (Seasonal Base) | | |
| Station Manager | 1 | 1 | 1 |
| **Maintenance/ Engineering / Asset Section** | | | |
| Maintenance Mgr./ Asset Mgr. | 1 | 2 | 2 |
| Maintenance Management Supervisors | 1 | 4 | 3 |
| Engineering Supervisors/ Asset & Mechanical | 1 | 0 | 4 |
| Engineers Asset / Maintenance | 4 | 6 | 4 |
| Mechanical Trades & Supervisors | 11 | 9 | 21 |
| Electrical & Instrument Trades & Supervisors | 16 | 12 | 23 |
| Communication Protection & Control | 2 | Corp | Corp |
| General Trades & Supervisors | 6 | 7 | 11 |
| **Operations Section** | | | |
| Operations Manager | 1 | 1 | 1 |
| Operations Management Supervisors | | 1 | 2 |
| Supervising Shift Engineers | 5 | 5 | 0 |
| Hands on Operators | 35 | 31 | 62 |
| Environment and Performance Manager (Safety, Health & Envir.) | 0 | 1 | 0 |
| Environmental Advisor (management) | 1 PT | 0 | 1 |
| Chemist or Chem. Group Leader | 1 | 1 | 1 |
| Chemical / Environment Technicians | 5 | 7 | 8 |
| Thermal Technical Specialist | 1 | 1 | 0 |
| **Office Administration** | | | |
| Administrator / Support Services Coordinator | 1 | 1 | 1 Corp |
| Clerical Staff | 4.5 | 3 | 2 |
| Corporate Finance | 0 | | 3 -Lnx only |
| **Planning** | | | |
| Manager or Leader | 1 | 1 | 1 |
| Schedulers/ Planning Technicians | 3 | 3 | 2 |
| Stores | 2 | 4 | 7 |
| Safety (+ Emerg. Response Team) | 1 | 1 (+5) | 1 Corp |
| Total | 103 | 107 | 162+ |

Notes: PT = Part Time, Corp= Corporate

Each of these facilities has adopted similar maintenance strategies. However, the numbers in the table indicate that Holyrood may require some additional electrical/instrumentation support and likely more administrative support, as well as the currently planned civil engineering support.

### 5.2.1 Staff Training

Holyrood operates as a seasonal base loaded plant between November and April and tends to be either on or off and generally operates between 70 and 130 MW. It has few starts per unit per year, typically less than twelve. As a result, the plant operators see a fair bit of operating time and at least some starts and stops as a component of their on the job training. The station also runs training programs periodically on issues that may arise during operation. It is thought that some "what do you do if this happens", and "why is it done that way" scenario training might be useful. Otherwise, the training program for all plant staff seems consistent with other thermal generating facilities.

## 5.3 Predictive and Preventative Maintenance Programs

Holyrood has a very active computer-based PM program. The program is currently being revised on a corporate basis in order to make it more practical, including the development of additional predictive approaches. This is seen as a very positive step for Holyrood, given its resources, role, and maintenance approach.

The system can be somewhat difficult to use effectively as a resource in parallel with the outage reporting system. Generally, the issue tends to be the format in which documentation is produced and a more user-friendly system would be useful.

## 5.4 Inspections – Regulatory and Other

NL Hydro has a strong commitment to align with regulatory requirements, insurance requirements, and industry practices. Holyrood is generally very thorough in its implementation of preventative maintenance programs, inspections, overhauls, and replacement of equipment.

Holyrood has a comprehensive maintenance inspection program. However, there have been some interruptions in the last few years related to some of the systems, primarily those considered less critical or less susceptible to a modest delay. One concern is that more should be done in the areas of high pressure piping inspections and boiler hanger inspections. A second is in the area of inspections associated with steam turbines and generators. The period between major steam turbine and generator inspections has been increased from six years to nine years, primarily based on the assessment of Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of the steam turbine and generator preventative maintenance inspection at Holyrood. Based on industry experience associated with similar equipment and the recent results of inspections and the condition of plant monitoring equipment, it is AMEC's position that the duration between major inspections and overhauls of the steam turbines can reasonably remain at nine years subject to the findings of each overhaul, but for the generators should be reduced back to six years.

## 5.5 Work Management Improvements

As mentioned previously, AMEC believes the maintenance strategy and the asset management program at Holyrood are well implemented in most areas of the operation and, for the most part, are consistent with other TGS's across North America.

One significant potential maintenance system improvement opportunity relates to the fact that some Holyrood employees still use hand written Work Orders (WO's) submitted for equipment deficiencies to the Holyrood planning office, which then transfer these to a computer program (duplication of effort). A number of other generating facilities now have all employees submitting WO's electronically. After being notified, that person will then be able to review the completed WO list generated by planning. Planning,

in consultation with operations and maintenance personnel, schedules the work and then the work is delegated to either a contractor or Holyrood staff.

A second improvement, and one that applies generally to the facility, is in the area of records management. This includes management of historical design information, operations and maintenance history, and management of current information. It was apparent during this study that while Holyrood is very good at inspections, maintenance, and overhauls, a document control system should be implemented.

## 5.6 Capital Improvements

Capital improvements completed over the last five to ten years at Holyrood should be commended. Replacing the water treatment plant systems and controls, installing a new air compressor, installing a new diesel generator set used for safe shutdown of the facility, boiler superheater replacements, and the installation of a new boiler chemical injection system increased the reliability and overall life of the plant. A listing of significant capital improvements has been included below in Table 5-2.

| ITEM | UPGRADE DESCRIPTION | YEAR |
|---|---|---|
| A. | Uprate Generation Units 1 and 2 (150 MW to 175 MW) | 1987 |
| B. | Upgrade Unit 3 to operate as a synchronous condenser | 1986 |
| C. | Major Turbine/Generator Disassembly, Overhaul and Repair | every 9 yrs |
| D. | Turbine/Generator Valves Disassembly, Inspection and Repair | every 3 yrs |
| E. | Boilers Internal Cleaning, Inspection and Minor Repairs | Annually |
| F. | Construct New Water Treatment Plant | 1992 |
| G. | Construct New Wastewater Treatment Plant | 1994 |
| H. | Replace Unit 1 Boiler Stack Liner | 2000 |
| I. | Replace Unit 2 Boiler Stack Liner | 2001 |
| J. | Upgrade Unit 1 Exciter | 2000 |
| K. | Upgrade Unit 2 Exciter | 1999 |
| L. | Upgrade Unit 1 Governor Controls | 2003 |
| M. | Upgrade Unit 2 Governor Controls | 1999 |
| N. | Replace Uninterrupted Power System | 2000 |
| O. | Replace Boilers Breeching | 1990 |
| P. | Upgrade Units 1, 2 Controls System | 1988 & 2004 |
| Q. | Upgrade Units 3 Controls System | 1994 & 2005 |
| R. | Install Warm Air Make-up System | 1992 |
| S. | Construct New Security Building | 2004 |
| T. | Plant Asbestos Removal Program (3 year project) | 2003-2006 |
| U. | Replace Boiler No. 2 Superheater | 2007 |
| V. | Replace Boiler No. 1 Superheater | 2008 |
| W. | Replace Roof and Upgrade Siding | 1990-2000 |
| X. | Replace Boiler No. 2 Partial Water Wall | 2006 |
| Y. | Install Boiler Soot Blower | 1995 |
| Z. | Upgrade Boiler Air Pre-heater Steam Heat Exchanger | 1990 |
| AA. | Install Continuous Emissions Monitoring System (shared) | 2003 |
| BB. | Construct five Ambient Air Monitoring Stations | 1993 |
| CC. | Replace Heating, Ventilation & Air Conditioning Units | 2002-2005 |
| DD. | Install Cooper Ion Injection System | 2007 |
| EE. | Replace Unit 2 Boiler Stop Valve | 2008 |
| FF. | High Pressure Feedwater Heater No.5 Replacement, Unit 2 | 2009 |
| GG. | Install Unit 2 Cold Reheat Drain Pots | 2009 |
| HH. | Refurbishment Unit 2 East & West Air Preheaters Cold End | 2009 |
| II. | Upgrade Tank Farm Phase 1 | 2009 |
| JJ. | Upgrade Fire Sprinkler System | 2008 |
| KK. | Gas Turbine PLC Replacement | 2009 |
| LL. | Install Marine Terminal Capsan Lifting Frames | 2009 |
| MM. | Unit 3 Steam Seal Regulator Replacement | 2009 |
| NN. | Unit 1 Emergency Hydrogen Venting | 2009 |

**FIGURE 5-2 SIGNIFICANT CAPITAL IMPROVEMENTS**

Several additional programs have been initiated in 2010 that are not shown in the figure including: the Steam Seal Regulator (SSR) obsolescence for Unit 1 currently underway (Unit 2 SSR is recommended to

be undertaken in 2011/2012); and the switchyard air compressor piping replacement started in 2010 and carrying through 2011.

As a result of the Lower Churchill Project and the HVDC line to the island, capital improvements at Holyrood will be more difficult to justify by the uncertainty going forward as a generating facility. There is no question that Holyrood continues to need capital improvements, largely in the electrical switchgear and motor control centers and protections. Some of these, however, are dedicated to the generation/steam side of the plant which, under the terms of this study, need only last until sometime between 2015 and 2020.

Some capital improvements that may be required are outside of the plant's jurisdiction such as the power transformers and switchyard equipment.

## 5.7 Maintenance Review Conclusions

NL Hydro is committed to meeting their regulatory, insurance, and safety requirements through ongoing inspections, maintenance, fire safety, and capital programs.

Holyrood is transitioning to its new PM program. The new program will increase the number of systems using a strategy that employs preventive and/or predictive methods to determine when the need for maintenance exists, given Holyrood's operating pattern. It will also update the maintenance requirements and detailed practices for plant systems.

The new Maintenance Program is believed to significantly improve an already good program, while optimizing costs. It should prevent some equipment from being under-resourced, such as the black start gas turbine which generally is only required when emergencies occur and thus deemed to have a lower priority in the larger scheme of work scheduling. It will also address and update several systems such as high pressure piping and pipe hangers that have received insufficient attention in recent times.



# 6 HOLYROOD OPERATING HISTORY & FUTURE ASSUMPTIONS

The following tables illustrate both the historical and assumed case operating regimes for the facility. The historical data includes the period to 2009 (2009 is highlighted). For the period beyond 2009, several scenarios were examined (Generation: 40% to 70% annual capacity factor (ACF) to 2015; 10% to 2020; Synchronous Condensing: as shown).

**TABLE 6-1 UNIT 1 - OPTION 1-1 - MODERATE GENERATION ACF TO 2015 LOW TO 2020**

| | | | | | | |
|---|---|---|---|---|---|---|
| Generation to 2015 | ACF– | 40% | 2016 to2020 | ACF– | 10% | |
| | Operating Factor – | 55% | | Operating Factor– | 20% | |
| Syncronous Condensing in 2015 | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 124740 | 328665 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 120000 | 323925 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 115260 | 319185 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 110520 | 314445 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 105780 | 309705 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 101040 | 304965 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 96300 | 300225 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 91560 | 295485 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 86820 | 290745 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 82080 | 286005 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 77340 | 281265 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 72600 | 276525 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 67860 | 271785 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 63120 | 267045 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 58380 | 262305 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 53640 | 257565 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 48900 | 252825 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 44160 | 248085 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 39420 | 243345 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 34680 | 238605 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 203925 | 4740 | 29940 | 233865 |
| 2020 | 10.0% | 148920 | 20.0% | 12 | 203925 | 4740 | 25200 | 229125 |
| 2019 | 10.0% | 148920 | 20.0% | 12 | 202173 | 4740 | 20460 | 222633 |
| 2018 | 10.0% | 148920 | 20.0% | 12 | 200421 | 4740 | 15720 | 216141 |
| 2017 | 10.0% | 148920 | 20.0% | 12 | 198669 | 4740 | 10980 | 209649 |
| 2016 | 10.0% | 148920 | 20.0% | 12 | 196917 | 4740 | 6240 | 203157 |
| 2015 | 40.0% | 595680 | 55.0% | 12 | 195165 | 1500 | 1500 | 196665 |
| 2014 | 40.0% | 595680 | 55.0% | 12 | 190347 | 0 | 0 | 190347 |
| 2013 | 40.0% | 595680 | 55.0% | 12 | 185529 | 0 | 0 | 185529 |
| 2012 | 40.0% | 595680 | 55.0% | 12 | 180711 | 0 | 0 | 180711 |
| 2011 | 40.0% | 595680 | 55.0% | 12 | 175893 | 0 | 0 | 175893 |
| 2010 | 40.0% | 595680 | 55.0% | 12 | 171075 | 0 | 0 | 171075 |
| 2009 | 23.5% | 360410 | 51.6% | 12 | 166257 | 0 | 0 | 166257 |
| 2008 | 19.1% | | 39.7% | 13 | 161737 | | | |
| 2007 | 25.5% | | 64.3% | 21 | 158261 | | | |
| 2006 | 20.5% | | 46.5% | 19 | 152632 | | | |
| 2005 | 28.4% | | 47.0% | 6 | 148555 | | | |
| 2004 | 42.2% | | 61.7% | 12 | 144438 | | | |
| 2003 | 44.3% | | 56.9% | 7 | 139034 | | | |
| 2002 | 55.3% | | 65.9% | 13 | 134050 | | | |
| 2001 | 50.2% | | 74.9% | 16 | 128275 | | | |
| 2000 | 29.2% | | 59.5% | 11 | 121715 | | | |
| 1999 | 25.8% | | 55.0% | 9 | 116501 | | | |
| 1998 | 35.4% | | 53.9% | 9 | 111687 | | | |
| 1997 | 36.1% | | 54.2% | 7 | 106970 | | | |
| 1996 | 35.7% | | 50.9% | 11 | 102226 | | | |
| 1995 | 47.3% | | 63.0% | 8 | 97771 | | | |
| 1994 | 18.4% | | 39.0% | 9 | 92250 | | | |
| 1993 | 48.4% | | 75.0% | 14 | 88832 | | | |
| 1992 | 46.3% | | 55.2% | 22 | 82258 | | | |
| 1991 | 49.6% | | 80.2% | 13 | 77420 | | | |
| 1990 | 48.5% | | 69.3% | 13 | 70396 | | | |
| 1989 | 71.9% | | 102.9% | 13 | 64322 | | | |
| 1988 | 28.9% | | 41.3% | 13 | 55311 | | | |
| 1987 | 49.2% | | 70.4% | 13 | 51689 | | | |
| 1986 | 55.9% | | 80.0% | 13 | 45522 | | | |
| 1985 | 30.3% | | 43.4% | 13 | 38512 | | | |
| 1984 | 20.2% | | 28.9% | 12 | 34710 | | | |
| 1983 | 17.4% | | 24.9% | 12 | 32174 | | | |
| 1982 | 33.2% | | 47.4% | 13 | 29994 | | | |
| 1981 | 10.8% | | 15.5% | 12 | 25839 | | | |
| 1980 | 42.2% | | 60.4% | 13 | 24486 | | | |
| 1979 | 43.1% | | 61.7% | 13 | 19193 | | | |
| 1978 | 30.3% | | 43.3% | 13 | 13786 | | | |
| 1977 | 15.4% | | 22.0% | 12 | 9994 | | | |
| 1976 | 15.3% | | 21.9% | 12 | 8070 | | | |
| 1975 | 15.3% | | 21.9% | 12 | 6149 | | | |
| 1974 | 11.4% | | 16.3% | 12 | 4233 | | | |
| 1973 | 8.6% | | 12.4% | 12 | 2805 | | | |
| 1972 | 2.7% | | 3.9% | 12 | 1723 | | | |
| 1971 | 11.0% | | 15.7% | 12 | 1378 | | | |
| 1970 | 1.7% | | 0.0% | | 0 | | | |
| 1969 | 0.0% | | 0.0% | | | | | |

## TABLE 6-2 UNIT 1 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

| | | | | | |
|---|---|---|---|---|---|
| Generation to 2015 | ACF= | 70% | 2016 to2020 | ACF= | 70% |
| | Operating Factor = | 85% | | Operating Factor= | 20% |
| Syncronous Condensing in 2015 | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 124740 | 344433 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 120000 | 339693 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 115260 | 334953 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 110520 | 330213 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 105780 | 325473 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 101040 | 320733 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 96300 | 315993 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 91560 | 311253 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 86820 | 306513 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 82080 | 301773 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 77340 | 297033 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 72600 | 292293 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 67860 | 287553 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 63120 | 282813 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 58380 | 278073 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 53640 | 273333 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 48900 | 268593 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 44160 | 263853 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 39420 | 259113 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 34680 | 254373 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 219693 | 4740 | 29940 | 249633 |
| 2020 | 10.0% | 148920 | 20.0% | 12 | 219693 | 4740 | 25200 | 244893 |
| 2019 | 10.0% | 148920 | 20.0% | 12 | 217941 | 4740 | 20460 | 238401 |
| 2018 | 10.0% | 148920 | 20.0% | 12 | 216189 | 4740 | 15720 | 231909 |
| 2017 | 10.0% | 148920 | 20.0% | 12 | 214437 | 4740 | 10980 | 225417 |
| 2016 | 10.0% | 148920 | 20.0% | 12 | 212685 | 4740 | 6240 | 218925 |
| 2015 | 70.0% | 1042440 | 85.0% | 12 | 210933 | 1500 | 1500 | 212433 |
| 2014 | 70.0% | 1042440 | 85.0% | 12 | 203487 | 0 | 0 | 203487 |
| 2013 | 70.0% | 1042440 | 85.0% | 12 | 196041 | 0 | 0 | 196041 |
| 2012 | 70.0% | 1042440 | 85.0% | 12 | 188595 | 0 | 0 | 188595 |
| 2011 | 70.0% | 1042440 | 85.0% | 12 | 181149 | 0 | 0 | 181149 |
| 2010 | 70.0% | 1042440 | 85.0% | 12 | 173703 | 0 | 0 | 173703 |
| 2009 | 23.5% | 360410 | 51.6% | 12 | 166257 | 0 | 0 | 166257 |
| 2008 | 19.1% | | 39.7% | 13 | 161737 | | | |
| 2007 | 25.5% | | 64.3% | 21 | 158261 | | | |
| 2006 | 20.5% | | 46.5% | 19 | 152632 | | | |
| 2005 | 28.4% | | 47.0% | 6 | 148555 | | | |
| 2004 | 42.2% | | 61.7% | 12 | 144438 | | | |
| 2003 | 44.3% | | 56.9% | 7 | 139034 | | | |
| 2002 | 55.3% | | 65.9% | 13 | 134050 | | | |
| 2001 | 50.2% | | 74.9% | 16 | 128275 | | | |
| 2000 | 29.2% | | 59.5% | 11 | 121715 | | | |
| 1999 | 25.8% | | 55.0% | 9 | 116501 | | | |
| 1998 | 35.4% | | 53.9% | 9 | 111687 | | | |
| 1997 | 36.1% | | 54.2% | 7 | 106970 | | | |
| 1996 | 35.7% | | 50.9% | 11 | 102226 | | | |
| 1995 | 47.3% | | 63.0% | 8 | 97771 | | | |
| 1994 | 18.4% | | 39.0% | 9 | 92250 | | | |
| 1993 | 48.4% | | 75.0% | 14 | 88832 | | | |
| 1992 | 46.3% | | 55.2% | 22 | 82258 | | | |
| 1991 | 49.6% | | 80.2% | 13 | 77420 | | | |
| 1990 | 48.5% | | 69.3% | 13 | 70396 | | | |
| 1989 | 71.9% | | 102.9% | 13 | 64322 | | | |
| 1988 | 28.9% | | 41.3% | 13 | 55311 | | | |
| 1987 | 49.2% | | 70.4% | 13 | 51689 | | | |
| 1986 | 55.9% | | 80.0% | 13 | 45522 | | | |
| 1985 | 30.3% | | 43.4% | 13 | 38512 | | | |
| 1984 | 20.2% | | 28.9% | 12 | 34710 | | | |
| 1983 | 17.4% | | 24.9% | 12 | 32174 | | | |
| 1982 | 33.2% | | 47.4% | 13 | 29994 | | | |
| 1981 | 10.8% | | 15.5% | 12 | 25839 | | | |
| 1980 | 42.2% | | 60.4% | 13 | 24486 | | | |
| 1979 | 43.1% | | 61.7% | 13 | 19193 | | | |
| 1978 | 30.3% | | 43.3% | 13 | 13786 | | | |
| 1977 | 15.4% | | 22.0% | 12 | 9994 | | | |
| 1976 | 15.3% | | 21.9% | 12 | 8070 | | | |
| 1975 | 15.3% | | 21.9% | 12 | 6149 | | | |
| 1974 | 11.4% | | 16.3% | 12 | 4233 | | | |
| 1973 | 8.6% | | 12.4% | 12 | 2805 | | | |
| 1972 | 2.7% | | 3.9% | 12 | 1723 | | | |
| 1971 | 11.0% | | 15.7% | 12 | 1378 | | | |
| 1970 | 1.7% | | 0.0% | | 0 | | | |
| 1969 | 0.0% | | 0.0% | | | | | |

## TABLE 6-3 UNIT 2 - OPTION 1-1 - MODERATE GENERAL ACF TO 2015, LOW TO 2020

| | | | | | |
|---|---|---|---|---|---|
| Generation to 2015 | ACF= | 40% | 2016 to2020 | ACF= | 10% |
| | Operating Factor = | 55% | | Operating Factor= | 20% |
| Syncronous Condensing in 2015 | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 124740 | 320697 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 120000 | 315957 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 115260 | 311217 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 110520 | 306477 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 105780 | 301737 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 101040 | 296997 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 96300 | 292257 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 91560 | 287517 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 86820 | 282777 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 82080 | 278037 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 77340 | 273297 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 72600 | 268557 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 67860 | 263817 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 63120 | 259077 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 58380 | 254337 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 53640 | 249597 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 48900 | 244857 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 44160 | 240117 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 39420 | 235377 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 34680 | 230637 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 195957 | 4740 | 29940 | 225897 |
| 2020 | 10.0% | 148920 | 20.0% | 12 | 195957 | 4740 | 25200 | 221157 |
| 2019 | 10.0% | 148920 | 20.0% | 12 | 194205 | 4740 | 20460 | 214665 |
| 2018 | 10.0% | 148920 | 20.0% | 12 | 192453 | 4740 | 15720 | 208173 |
| 2017 | 10.0% | 148920 | 20.0% | 12 | 190701 | 4740 | 10980 | 201681 |
| 2016 | 10.0% | 148920 | 20.0% | 12 | 188949 | 4740 | 6240 | 195189 |
| 2015 | 40.0% | 595680 | 55.0% | 12 | 187197 | 1500 | 1500 | 188697 |
| 2014 | 40.0% | 595680 | 55.0% | 12 | 182379 | 0 | 0 | 182379 |
| 2013 | 40.0% | 595680 | 55.0% | 12 | 177561 | 0 | 0 | 177561 |
| 2012 | 40.0% | 595680 | 55.0% | 12 | 172743 | 0 | 0 | 172743 |
| 2011 | 40.0% | 595680 | 55.0% | 12 | 167925 | 0 | 0 | 167925 |
| 2010 | 40.0% | 595680 | 55.0% | 12 | 163107 | 0 | 0 | 163107 |
| 2009 | 25.7% | 394200 | 56.2% | 6 | 158289 | 0 | 0 | 158289 |
| 2008 | 35.8% | | 56.9% | 8 | 153367 | | | |
| 2007 | 36.7% | | 58.3% | 9 | 148386 | | | |
| 2006 | 10.5% | | 28.4% | 7 | 143279 | | | |
| 2005 | 30.7% | | 52.6% | 13 | 140789 | | | |
| 2004 | 33.2% | | 50.0% | 12 | 136186 | | | |
| 2003 | 48.6% | | 69.5% | 14 | 131805 | | | |
| 2002 | 58.3% | | 69.3% | 13 | 125721 | | | |
| 2001 | 57.8% | | 78.6% | 10 | 119655 | | | |
| 2000 | 27.5% | | 61.6% | 11 | 112771 | | | |
| 1999 | 16.7% | | 43.4% | 12 | 107373 | | | |
| 1998 | 32.8% | | 52.4% | 9 | 103573 | | | |
| 1997 | 41.2% | | 59.4% | 8 | 98987 | | | |
| 1996 | 37.2% | | 58.0% | 21 | 93783 | | | |
| 1995 | 33.0% | | 45.7% | 14 | 88702 | | | |
| 1994 | 21.0% | | 49.1% | 7 | 84696 | | | |
| 1993 | 30.0% | | 45.6% | 17 | 80400 | | | |
| 1992 | 35.2% | | 53.5% | 15 | 76408 | | | |
| 1991 | 25.6% | | 38.4% | 11 | 71720 | | | |
| 1990 | 44.6% | | 66.9% | 13 | 68352 | | | |
| 1989 | 18.9% | | 28.3% | 11 | 62489 | | | |
| 1988 | 44.7% | | 67.0% | 13 | 60009 | | | |
| 1987 | 64.6% | | 96.9% | 14 | 54136 | | | |
| 1986 | 31.0% | | 46.5% | 12 | 45647 | | | |
| 1985 | 52.4% | | 78.6% | 13 | 41576 | | | |
| 1984 | 11.8% | | 17.7% | 10 | 34694 | | | |
| 1983 | 17.8% | | 26.7% | 11 | 33144 | | | |
| 1982 | 35.6% | | 53.4% | 12 | 30804 | | | |
| 1981 | 2.4% | | 3.6% | 9 | 26129 | | | |
| 1980 | 34.7% | | 52.0% | 12 | 25811 | | | |
| 1979 | 48.6% | | 72.8% | 13 | 21253 | | | |
| 1978 | 33.8% | | 50.8% | 12 | 14872 | | | |
| 1977 | 13.8% | | 20.6% | 10 | 10426 | | | |
| 1976 | 11.4% | | 17.0% | 10 | 8618 | | | |
| 1975 | 8.9% | | 13.4% | 10 | 7125 | | | |
| 1974 | 16.1% | | 24.1% | 10 | 5951 | | | |
| 1973 | 10.2% | | 15.4% | 10 | 3838 | | | |
| 1972 | 12.6% | | 18.8% | 10 | 2493 | | | |
| 1971 | 6.4% | | 9.6% | 10 | 844 | | | |
| 1970 | 0.0% | | 0.0% | | 0 | | | |
| 1969 | 0.0% | | 0.0% | | | | | |

## TABLE 6-4 UNIT 2 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

| | | | | | |
|---|---|---|---|---|---|
| Generation to 2015 | ACF= | 70% | 2016 to2020 | ACF= | 70% |
| | Operating Factor = | 85% | | Operating Factor= | 20% |
| Syncronous Condensing in 2015 | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 124740 | 336465 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 120000 | 331725 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 115260 | 326985 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 110520 | 322245 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 105780 | 317505 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 101040 | 312765 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 96300 | 308025 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 91560 | 303285 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 86820 | 298545 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 82080 | 293805 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 77340 | 289065 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 72600 | 284325 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 67860 | 279585 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 63120 | 274845 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 58380 | 270105 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 53640 | 265365 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 48900 | 260625 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 44160 | 255885 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 39420 | 251145 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 34680 | 246405 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 211725 | 4740 | 29940 | 241665 |
| 2020 | 10.0% | 148920 | 20.0% | 12 | 211725 | 4740 | 25200 | 236925 |
| 2019 | 10.0% | 148920 | 20.0% | 12 | 209973 | 4740 | 20460 | 230433 |
| 2018 | 10.0% | 148920 | 20.0% | 12 | 208221 | 4740 | 15720 | 223941 |
| 2017 | 10.0% | 148920 | 20.0% | 12 | 206469 | 4740 | 10980 | 217449 |
| 2016 | 10.0% | 148920 | 20.0% | 12 | 204717 | 4740 | 6240 | 210957 |
| 2015 | 70.0% | 1042440 | 85.0% | 12 | 202965 | 1500 | 1500 | 204465 |
| 2014 | 70.0% | 1042440 | 85.0% | 12 | 195519 | 0 | 0 | 195519 |
| 2013 | 70.0% | 1042440 | 85.0% | 12 | 188073 | 0 | 0 | 188073 |
| 2012 | 70.0% | 1042440 | 85.0% | 12 | 180627 | 0 | 0 | 180627 |
| 2011 | 70.0% | 1042440 | 85.0% | 12 | 173181 | 0 | 0 | 173181 |
| 2010 | 70.0% | 1042440 | 85.0% | 12 | 165735 | 0 | 0 | 165735 |
| 2009 | 25.7% | 394200 | 56.2% | 6 | 158289 | 0 | 0 | 158289 |
| 2008 | 35.8% | | 56.9% | 8 | 153367 | | | |
| 2007 | 36.7% | | 58.3% | 9 | 148386 | | | |
| 2006 | 10.5% | | 28.4% | 7 | 143279 | | | |
| 2005 | 30.7% | | 52.6% | 13 | 140789 | | | |
| 2004 | 33.2% | | 50.0% | 12 | 136186 | | | |
| 2003 | 48.6% | | 69.5% | 14 | 131805 | | | |
| 2002 | 58.3% | | 69.3% | 13 | 125721 | | | |
| 2001 | 57.8% | | 78.6% | 10 | 119655 | | | |
| 2000 | 27.5% | | 61.6% | 11 | 112771 | | | |
| 1999 | 16.7% | | 43.4% | 12 | 107373 | | | |
| 1998 | 32.8% | | 52.4% | 9 | 103573 | | | |
| 1997 | 41.2% | | 59.4% | 8 | 98987 | | | |
| 1996 | 37.2% | | 58.0% | 21 | 93783 | | | |
| 1995 | 33.0% | | 45.7% | 14 | 88702 | | | |
| 1994 | 21.0% | | 49.1% | 7 | 84696 | | | |
| 1993 | 30.0% | | 45.6% | 17 | 80400 | | | |
| 1992 | 35.2% | | 53.5% | 15 | 76408 | | | |
| 1991 | 25.6% | | 38.4% | 11 | 71720 | | | |
| 1990 | 44.6% | | 66.9% | 13 | 68352 | | | |
| 1989 | 18.9% | | 28.3% | 11 | 62489 | | | |
| 1988 | 44.7% | | 67.0% | 13 | 60009 | | | |
| 1987 | 64.6% | | 96.9% | 14 | 54136 | | | |
| 1986 | 31.0% | | 46.5% | 12 | 45647 | | | |
| 1985 | 52.4% | | 78.6% | 13 | 41576 | | | |
| 1984 | 11.8% | | 17.7% | 10 | 34694 | | | |
| 1983 | 17.8% | | 26.7% | 11 | 33144 | | | |
| 1982 | 35.6% | | 53.4% | 12 | 30804 | | | |
| 1981 | 2.4% | | 3.6% | 9 | 26129 | | | |
| 1980 | 34.7% | | 52.0% | 12 | 25811 | | | |
| 1979 | 48.6% | | 72.8% | 13 | 21253 | | | |
| 1978 | 33.8% | | 50.8% | 12 | 14872 | | | |
| 1977 | 13.8% | | 20.6% | 10 | 10426 | | | |
| 1976 | 11.4% | | 17.0% | 10 | 8618 | | | |
| 1975 | 8.9% | | 13.4% | 10 | 7125 | | | |
| 1974 | 16.1% | | 24.1% | 10 | 5951 | | | |
| 1973 | 10.2% | | 15.4% | 10 | 3838 | | | |
| 1972 | 12.6% | | 18.8% | 10 | 2493 | | | |
| 1971 | 6.4% | | 9.6% | 10 | 844 | | | |
| 1970 | 0.0% | | 0.0% | | 0 | | | |
| 1969 | 0.0% | | 0.0% | | | | | |

## TABLE 6-5 UNIT 3 - OPTION 1-1 - MODERATE GENERATION ACF TO 2015, LOW TO 2020

| | | | | | |
|---|---|---|---|---|---|
| Generation to 2015 | ACF– | 40% | 2016 to2020 | ACF– | 10% |
| | Operating Factor – | 55% | | Operating Factor– | 20% |
| Syncronous Condensing in 2016+ | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | |
| Syncronous Condensing in 2011-201 | | 1500 | Hrs/Yr | | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 167313 | 330644 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 162573 | 325904 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 157833 | 321164 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 153093 | 316424 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 148353 | 311684 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 143613 | 306944 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 138873 | 302204 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 134133 | 297464 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 129393 | 292724 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 124653 | 287984 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 119913 | 283244 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 115173 | 278504 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 110433 | 273764 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 105693 | 269024 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 100953 | 264284 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 96213 | 259544 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 91473 | 254804 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 86733 | 250064 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 81993 | 245324 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 77253 | 240584 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 163331 | 4740 | 72513 | 235844 |
| 2020 | 10.0% | 131400 | 20.0% | 12 | 163331 | 4740 | 67773 | 231104 |
| 2019 | 10.0% | 131400 | 20.0% | 12 | 161579 | 4740 | 63033 | 224612 |
| 2018 | 10.0% | 131400 | 20.0% | 12 | 159827 | 4740 | 58293 | 218120 |
| 2017 | 10.0% | 131400 | 20.0% | 12 | 158075 | 4740 | 53553 | 211628 |
| 2016 | 10.0% | 131400 | 20.0% | 12 | 156323 | 4740 | 48813 | 205136 |
| 2015 | 40.0% | 525600 | 55.0% | 12 | 154571 | 1500 | 44073 | 198644 |
| 2014 | 40.0% | 525600 | 55.0% | 12 | 149753 | 1500 | 42573 | 192326 |
| 2013 | 40.0% | 525600 | 55.0% | 12 | 144935 | 1500 | 41073 | 186008 |
| 2012 | 40.0% | 525600 | 55.0% | 12 | 140117 | 1500 | 39573 | 179690 |
| 2011 | 40.0% | 525600 | 55.0% | 12 | 135299 | 1500 | 38073 | 173372 |
| 2010 | 40.0% | 525600 | 55.0% | 12 | 130481 | 1500 | 36573 | 167054 |
| 2009 | 19.1% | 251130 | 33.6% | 4 | 125663 | 35073 | 35073 | 160736 |
| 2008 | 23.6% | | 35.1% | 5 | 122717 | 30956 | | |
| 2007 | 29.4% | | 49.3% | 11 | 119643 | 26656 | | |
| 2006 | 24.7% | | 53.6% | 9 | 115322 | 25904 | | |
| 2005 | 38.7% | | 59.0% | 14 | 110627 | 23204 | | |
| 2004 | 44.8% | | 59.2% | 9 | 105455 | 22076 | | |
| 2003 | 48.4% | | 60.2% | 12 | 100272 | 20922 | | |
| 2002 | 58.6% | | 65.3% | 15 | 94998 | 19622 | | |
| 2001 | 42.8% | | 59.8% | 11 | 89282 | 18468 | | |
| 2000 | 13.0% | | 26.5% | 4 | 84043 | 17314 | | |
| 1999 | 26.0% | | 59.2% | 6 | 81726 | 16159 | | |
| 1998 | 22.6% | | 28.3% | 4 | 76541 | 15005 | | |
| 1997 | 33.6% | | 49.3% | 10 | 74066 | 13851 | | |
| 1996 | 28.6% | | 42.1% | 9 | 69745 | 12697 | | |
| 1995 | 30.1% | | 41.3% | 20 | 66058 | 11542 | | |
| 1994 | 18.3% | | 34.0% | 21 | 62436 | 10388 | | |
| 1993 | 35.0% | | 55.1% | 13 | 59461 | 9234 | | |
| 1992 | 42.8% | | 73.3% | 12 | 54633 | 8080 | | |
| 1991 | 28.2% | | 44.8% | 8 | 48216 | 6925 | | |
| 1990 | 39.5% | | 52.3% | 12 | 44294 | 5771 | | |
| 1989 | 56.5% | | 74.7% | 15 | 39717 | 4617 | | |
| 1988 | 39.9% | | 52.8% | 12 | 33174 | 3463 | | |
| 1987 | 61.8% | | 81.6% | 16 | 28552 | 2308 | | |
| 1986 | 14.6% | | 19.2% | 8 | 21402 | 1154 | | |
| 1985 | 56.0% | | 73.9% | 15 | 19716 | | | |
| 1984 | 29.6% | | 39.1% | 10 | 13240 | | | |
| 1983 | 11.5% | | 15.2% | 8 | 9814 | | | |
| 1982 | 21.2% | | 28.0% | 9 | 8481 | | | |
| 1981 | 20.8% | | 27.5% | 9 | 6028 | | | |
| 1980 | 31.1% | | 41.0% | 11 | 3623 | | | |
| 1979 | 0.2% | | 0.3% | 6 | 29 | | | |
| 1978 | 0.0% | | 0.0% | | 0 | | | |
| 1977 | 0.0% | | 0.0% | | 0 | | | |
| 1976 | 0.0% | | 0.0% | | 0 | | | |
| 1975 | 0.0% | | 0.0% | | 0 | | | |
| 1974 | 0.0% | | 0.0% | | 0 | | | |
| 1973 | 0.0% | | 0.0% | | 0 | | | |
| 1972 | 0.0% | | 0.0% | | 0 | | | |
| 1971 | 0.0% | | 0.0% | | 0 | | | |
| 1970 | 0.0% | | 0.0% | | 0 | | | |
| 1969 | | | 0.0% | | | | | |

## TABLE 6-6 UNIT 3 - OPTION 2-1 - HIGH GENERATION ACF TO 2015, LOW TO 2020

| | | | | | |
|---|---|---|---|---|---|
| Generation to 2015 | ACF= | 70% | 2016 to2020 | ACF= | 70% |
| | Operating Factor = | 85% | | Operating Factor= | 20% |
| Syncronous Condensing in 2016+ | | 4740 | Hrs/Yr | (1500 av to date + 6 mos x 30 days x7d/wk + 75% of time) | |
| Syncronous Condensing in 2011-20 | | 1500 | Hrs/Yr | | |

| Year | ACF | MWh/Yr | Operating Factor % | Starts Per Year | Generation OP Hrs Cumulative Lifetime | Synch Cond OP Hrs Per Year | Synch Cond OP Hrs Cum | Total OP Hrs Cum Lifetime SC+Gen |
|---|---|---|---|---|---|---|---|---|
| 2041 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 167313 | 346412 |
| 2040 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 162573 | 341672 |
| 2039 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 157833 | 336932 |
| 2038 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 153093 | 332192 |
| 2037 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 148353 | 327452 |
| 2036 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 143613 | 322712 |
| 2035 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 138873 | 317972 |
| 2034 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 134133 | 313232 |
| 2033 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 129393 | 308492 |
| 2032 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 124653 | 303752 |
| 2031 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 119913 | 299012 |
| 2030 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 115173 | 294272 |
| 2029 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 110433 | 289532 |
| 2028 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 105693 | 284792 |
| 2027 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 100953 | 280052 |
| 2026 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 96213 | 275312 |
| 2025 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 91473 | 270572 |
| 2024 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 86733 | 265832 |
| 2023 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 81993 | 261092 |
| 2022 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 77253 | 256352 |
| 2021 | 0.0% | 0 | 0.0% | 5 | 179099 | 4740 | 72513 | 251612 |
| 2020 | 10.0% | 131400 | 20.0% | 12 | 179099 | 4740 | 67773 | 246872 |
| 2019 | 10.0% | 131400 | 20.0% | 12 | 177347 | 4740 | 63033 | 240380 |
| 2018 | 10.0% | 131400 | 20.0% | 12 | 175595 | 4740 | 58293 | 233888 |
| 2017 | 10.0% | 131400 | 20.0% | 12 | 173843 | 4740 | 53553 | 227396 |
| 2016 | 10.0% | 131400 | 20.0% | 12 | 172091 | 4740 | 48813 | 220904 |
| 2015 | 70.0% | 919800 | 85.0% | 12 | 170339 | 1500 | 44073 | 214412 |
| 2014 | 70.0% | 919800 | 85.0% | 12 | 162893 | 1500 | 42573 | 205466 |
| 2013 | 70.0% | 919800 | 85.0% | 12 | 155447 | 1500 | 41073 | 196520 |
| 2012 | 70.0% | 919800 | 85.0% | 12 | 148001 | 1500 | 39573 | 187574 |
| 2011 | 70.0% | 919800 | 85.0% | 12 | 140555 | 1500 | 38073 | 178628 |
| 2010 | 70.0% | 919800 | 85.0% | 12 | 133109 | 1500 | 36573 | 169682 |
| 2009 | 19.1% | 251130 | 33.6% | 4 | 125663 | 35073 | 35073 | 160736 |
| 2008 | 23.6% | | 35.1% | 5 | 122717 | 30956 | | |
| 2007 | 29.4% | | 49.3% | 11 | 119643 | 26656 | | |
| 2006 | 24.7% | | 53.6% | 9 | 115322 | 25904 | | |
| 2005 | 38.7% | | 59.0% | 14 | 110627 | 23204 | | |
| 2004 | 44.8% | | 59.2% | 9 | 105455 | 22076 | | |
| 2003 | 48.4% | | 60.2% | 12 | 100272 | 20922 | | |
| 2002 | 58.6% | | 65.3% | 15 | 94998 | 19622 | | |
| 2001 | 42.8% | | 59.8% | 11 | 89282 | 18468 | | |
| 2000 | 13.0% | | 26.5% | 4 | 84043 | 17314 | | |
| 1999 | 26.0% | | 59.2% | 6 | 81726 | 16159 | | |
| 1998 | 22.6% | | 28.3% | 4 | 76541 | 15005 | | |
| 1997 | 33.6% | | 49.3% | 10 | 74066 | 13851 | | |
| 1996 | 28.6% | | 42.1% | 9 | 69745 | 12697 | | |
| 1995 | 30.1% | | 41.3% | 20 | 66058 | 11542 | | |
| 1994 | 18.3% | | 34.0% | 21 | 62436 | 10388 | | |
| 1993 | 35.0% | | 55.1% | 13 | 59461 | 9234 | | |
| 1992 | 42.8% | | 73.3% | 12 | 54633 | 8080 | | |
| 1991 | 28.2% | | 44.8% | 8 | 48216 | 6925 | | |
| 1990 | 39.5% | | 52.3% | 12 | 44294 | 5771 | | |
| 1989 | 56.5% | | 74.7% | 15 | 39717 | 4617 | | |
| 1988 | 39.9% | | 52.8% | 12 | 33174 | 3463 | | |
| 1987 | 61.8% | | 81.6% | 16 | 28552 | 2308 | | |
| 1986 | 14.6% | | 19.2% | 8 | 21402 | 1154 | | |
| 1985 | 56.0% | | 73.9% | 15 | 19716 | | | |
| 1984 | 29.6% | | 39.1% | 10 | 13240 | | | |
| 1983 | 11.5% | | 15.2% | 8 | 9814 | | | |
| 1982 | 21.2% | | 28.0% | 9 | 8481 | | | |
| 1981 | 20.8% | | 27.5% | 9 | 6028 | | | |
| 1980 | 31.1% | | 41.0% | 11 | 3623 | | | |
| 1979 | 0.2% | | 0.3% | 6 | 29 | | | |
| 1978 | 0.0% | | 0.0% | | 0 | | | |
| 1977 | 0.0% | | 0.0% | | 0 | | | |
| 1976 | 0.0% | | 0.0% | | 0 | | | |
| 1975 | 0.0% | | 0.0% | | 0 | | | |
| 1974 | 0.0% | | 0.0% | | 0 | | | |
| 1973 | 0.0% | | 0.0% | | 0 | | | |
| 1972 | 0.0% | | 0.0% | | 0 | | | |
| 1971 | 0.0% | | 0.0% | | 0 | | | |
| 1970 | 0.0% | | 0.0% | | 0 | | | |
| 1969 | | | 0.0% | | | | | |

For the gas turbine generator, the NL Hydro operating data provided is:

Hours Actual - Operation to Dec 2005 (Estimated from 2005 to 2010)

- 1978 – 1,749 operating hrs since new (+85,000 idle hours)
- 1985 – 2,139 operating hrs since new (+170,000 idle hours)
- 1995 – 3,475 operating hrs since new (+256,000 idle hours)
- 2005 – 3,807 operating hrs since new (+343,000 idle hours)
- 2010 – 4,717 operating hrs since new (+381,000 idle hours)

The starts identified (including actuals to Dec 2005 and estimated to 2010) are:

- 1978 – 611 starts, since new
- 1985 – 796 starts, since new
- 1995 – 1,440 starts, since new
- 2005 – 2,025 starts, since new
- 2010 – 2,548 starts since new

Given that the combustor and the PT volute have been replaced or refurbished, AMEC have estimated the maximum hours of operation that the components may have experienced to an end date of 2020 (Assuming 4717 hours in 2010) to be:

- Combustor: 1,100 to 2,200 operating hours
- PT Volute: 2,600 to 4,700 operating hours
- Balance: 5,700 to 6,8400 operating hours

(NOTE: reduce or add about 100 to 200 operating hours per year for any difference in end date.)

Similarly, AMEC have estimated the maximum number of starts that the components may have experienced to an end date of 2020 (assuming 2,548 starts in 2010) to be:

- Combustor: 1,300 starts
- PT Volute: 2,100 starts
- Balance: 2,900 starts

(NOTE: reduce or add about 35 starts per year for any difference in end date.)



# 7 OVERALL PLANT CONDITION ASSESSMENT

Holyrood is considered to be a relatively modern design plant and in good condition.

Holyrood is expected to be able to meet either the 2015 or 2020 dates for the end of its electricity generation role with capital refurbishments and replacements primarily due to typical mid-life refurbishment requirements, old age effects and obsolescence. Some may also be impacted by the ambient humid, seaside environment. These are detailed later in the body of the report, but examples of would include many of the breakers and motor control centres, the waste water treatment basin building structure and ventilation system, the plant elevator, and equipment such as vacuum pumps, emergency diesels and air compressors. To minimize a decrease in reliability, additional spares such as a spare 4 kV motor for each of a boiler feed pump, a forced draft fan, and a circulating water pump are recommended. A complete overhaul or replacement of the gas turbine generator and balance of plant would also be recommended given its importance in a return to operation in the event of a system failure and its use as a system emergency power source.

Holyrood is also expected to be able to meet its 2041 synchronous condenser end of life, but will require some further substantial equipment refurbishments and replacements specific to that role that are identified later in the report. Examples of these would include generator rewinds, powerhouse and pump house roof replacements, switchyard breakers and motorized switches, synchronous condensing conversions.

Fossil plants of the same era as Holyrood were designed with an economic life of 30 years. For practical purposes, this meant at least a 40 year technical life. However, many plants in the United States are still in active service and quite functional at over 60 years of age.

Holyrood Units 1 2, and 3 are approximately 41, 40, and 31 years of age respectively. However, given their historical seasonal based, lightly loaded service, the operational age for the majority of its equipment and systems is more like 20, 19, and 16 years, respectively. The plant has been well managed and maintained. The units have also seen minimum service at either their maximum continuous rating (let alone over-pressure/over-temperature) or at extreme minimum load. The units tend to operate between 70 and 140 MW (40% and 80% load) and most often around 110 to 125 MW (65-70%). Unit 3 has seen modest synchronous condensing operation since its retrofit in 1986.

As mentioned previously, Units 1 and 2 were uprated from 150 to 175 MW in 1987. The components that were modified or replaced during the unit upgrade have a longer life as compared to the original equipment. These support a longer life expectation for the station as a whole.

The boiler and its major elements were one of the plant's major reliability and life issues. The original high sulphur (2.5%) and high vanadium fuel oil caused significant corrosion and fouling problems that led to upgrades to some of the boiler heat transfer surfaces. In 2009, the change to a higher quality, lower sulphur (0.7%) fuel oil has significantly improved boiler reliability and efficiency and is expected to have a positive impact on the life of boiler systems.

As indicated above, there is no reason why the plant cannot continue to generate electricity reliably to the year 2020 as identified. Similarly, if and when Units 1 and 2 are converted to synchronous condensers (current plan is conversion in 2014) to provide system support, the units and the plant should be able to fulfill that role to 2041. There are several pre-requisites to this, including continued and enhanced inspection and maintenance programs, planned major equipment refurbishment such as generator stator and rotor rewinds, controls and alarms upgrades, and switchgear and breaker refurbishments and replacements.

A key to extending plant life will be the generators, transformers, and switchgear. Units 1, 2, and 3 have major generator inspections scheduled for 2012, 2014, and 2016 respectively. They also have reliability issues that may require a near term need for stator and/or rotor rewinds and possibly core or rotor replacement. Transformers are at the point in their lifecycle where significant degradation also occurs. More frequent or continuous monitoring of their condition is required to forewarn of any problems arising. Existing switchgear is in many cases at or near end of life and refurbishment and replacement is required.

Several other key issues with single contingency systems, given age and failure history also raise red flags and include:

- The single contingency failure risk of the fresh/raw water supply from Quarry Brook Pond;
- The single contingency failure risk of the clarifier failure, at least until 2020; and
- The 42 year age and condition of the black start gas turbine – reliability, parts obsolescence make a detailed evaluation critical; especially as the island interconnected system has indicated a potential need for it as an emergency power source.

If Hydro addresses the key issues and maintains a vigorous maintenance and inspection program, there is no technical reason that the plant cannot reach its 2020 generation end of life and 2041 synchronous condensing end of life targets.

The gas turbine generator and balance of plant is in need of a major overhaul, as well as refurbishment and replacement of its stack and air intake systems. In addition, it is likely that it's fuel receiving and feeding system will need a major overhaul as soon as practical within the next two years.

# 8 UNIT 1

## 8.1 Unit 1 - Key Systems

### 8.1.1 Asset 6696 – Unit 1 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)



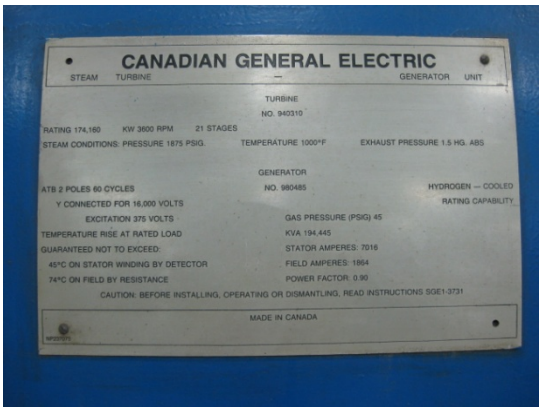



**FIGURE 8-1 UNIT 1 GENERATOR**

Equipment/components covered in this report are:

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6691 #1 Turbine & Generator |
| Sub-Systems: | 6696 #1 Generator Assembly |
| Components: | 6839 #1 Generator Rotor |
| | 6840 #1 Generator Stator |
| | 6849 #1 Excitation System |
| | 6850 #1 Hydrogen System |

#### 8.1.1.1 Description

Unit 1 generator, supplied by Canadian General Electric, Peterborough, is hydrogen-cooled and rated at 194,445 KVA. It went into service in 1969 and the last major inspection was in 2003. The 2003 outage inspection report is the base reference for this assessment.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at a pressure of 310 kPag (45 psig) by an axial fan mounted on each end of the rotor. An isolated phase bus delivers the power from the generator to the unit transformer.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent hydrogen from escaping around the rotating shaft. The seals are pressurised by oil and are located inboard of the bearings. The field windings are directly-cooled by hydrogen, fed via axial sub-slots and radial gas passages in the copper winding. The field windings are supported by retaining rings shrunk onto the ends of the rotor body. The field current is supplied to the field windings via collector rings and brush gear, outboard of the main bearing – there is no steady bearing. There is an unused thrust bearing collar at the turbine end of the generator shaft, for future synchronous condenser use.

The excitation to the field is now supplied by an ABB Unitrol static thyristor excitation system, with a fast response automatic voltage regulator to control the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled exciter fed from the generator terminals, with field flashing for initial energization;
- A seal oil system, with a differential pressure controller to keep the hydrogen contained within the generator;
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator;
- A hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required);
- A scavenging system to remove the hydrogen that becomes entrained in the bearing oil and the seal oil;
- Potential transformers (PT's), located below the isolated phase bus, measure the generator voltage; current transformers (CT's) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system continuously monitors the vibration amplitudes at each turbine generator bearing in the control room, and alerts the operator to increasing vibration, especially during run-up, load changes and shut-down. It uses two proximity probes at 45° to the vertical to measure the shaft vibration level; and
- A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings (which are in poor condition - see next item). It also provides supplementary alarms and sequence-of-events monitoring.

#### 8.1.1.2 History

The history and requirements for the Unit 1 generator are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Inspection | 2003 |
| Next Major Overhaul/Inspection | 2012 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 166 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 210 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 219 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 219 | 120 |
| Starts Actual - Ops to Dec 2009 | 482 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 714 | 130 |

#### 8.1.1.3 Inspection and Repair History

**Post-2003 Improvements**

- Fast dump of generator hydrogen added to supplement water sprays on bearings;
- Generator hydrogen dryer replaced;
- Hydrogen purity meter replaced; and
- Improved stator winding ground fault protection installed.

**2003 Overhaul**

- Full replacement of the stator slot wedges with top ripple springs;
- Stator end-winding support system cleaned and re-tightened;
- Defective RTD repaired. Accuracy of others is poor, (but they can only be replaced during replacement of the stator windings);
- Digital multi-functional generator protection relay installed, (for improved winding ground protection, alarms connected, and sequence of events monitoring). Electro-mechanical protection relays retained;
- Installed 4 new cold gas RTD's in stator;
- Damaged epoxy dowels of fibre inner end-shields – repaired with oversize dowels. Realigned hydrogen seal housing;
- Repaired leak in bushing box horizontal joint with RTV sealant. Joint needs a new gasket;
- Hydrogen coolers cleaned, and pressure tested. OK;

- Rotor shaft line realigned. Stator frame re-aligned to match rotor shaft, locking keys re-welded in frame base;
- Replaced improper flanges and gaskets and piping at liquid leak detector;
- Replaced and machined teeth of bearing oil deflectors (excessive clearances, chipped); and
- Repaired leak in horizontal joint of CE hydrogen seal with epoxy.

**1997 Overhaul**

- New 18%Mn/18%Cr retaining rings fitted to rotor;
- The end-portions of the field windings would be inspected while the rings were off, but no report was available. It is not known whether the rotor dovetails were NDE inspected for fatigue cracks;
- GE static exciter replaced by ABB Unitrol static exciter and Automotive Voltage Regulator (AVR) (In-service 2001); and
- Partial discharge monitoring system installed in stator windings.

### 8.1.1.4 Condition Assessment

The generator and its auxiliary systems are in reasonable good condition for their age.

- Stator core: satisfactory, based on EL-cid results;
- Stator Windings: Poor, based on Megger test and DC hipot test;
- Rotor Forging: Not known (appears not checked in past 20 years); and
- Field Winding: Satisfactory, but few details available (concerns are based on repairs made to similar GE rotors).

Details of the sub-systems are presented in Table 8-1 below and in more detail in Appendix 4.

**TABLE 8-1 CONDITION ASSESSMENT – UNIT 1 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 0 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE & GENERATOR | TURBINE & GENERATOR | N/A | 1 | 4 | Overhaul required in 2012 | 4 | 200000 (30) | 5 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | | 2 | 4 | Stator: core - satisfactory; Windings: Poor<br>Rotor: Forging: Not known, likely satisfactory; Winding: Satisfactory, but limited information<br>Overhaul required in 2012 | 4 | 200000 (30) | 5 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | CORE | 3 | 4 | Forging: Not known, likely satisfactory | 4 | 200000 (40) | 15 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | WINDINGS | 4 | 4 | Field Winding: Satisfactory, but little information. The field current is not credible: much too low. The field winding temperature is not monitored. No on-line monitoring for shorted field turns (most common indication the rotor needs to be re-wound) is in place. Partial discharge monitoring is not working. The shaft voltage and the shaft ground current are not monitored in operation for harmful currents through the bearing or hydrogen seal. The retaining rings, the rotor forging, and slot wedges do not appear to have been NDE checked for defects 1997. | 4 | 200000 (30) | 10 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | CORE | 5 | 4 | Core - satisfactory. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore, or at the outside flexible mounting. GE reported that EL-cid readings taken before and after the re-wedging of the stator bars in 2003 show no significant core deterioration, and the stator core is fit to be re-wound.<br>The stator winding and core RTD's do not read credible values: too low | 4 | 200000 (40) | (5+) | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | WINDINGS | 6 | 4 | Windings: Poor, requiring rewind. Reported in 2003 major outage to be in very poor condition with two of three phases significantly weaker and insulation weakness (or wetness). It is anticipated that more extensive loosening, fretting, and greasing of the end-windings will be found at the next inspection. Stator winding RTD's do not read credible values: too low | 4 | 200000 (30) | (2/8) | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 7345 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. STANDOFF INSULATORS | N/A | 7 | 4 | Excessive greasing of the stand-off insulators and of the flexible line leads to the potential transformers in the past required their replacement. 2003 stator re-alignment is expected to have reduced the vibration and stress on these components. Assess in overhaul. | 4 | (30) | 20 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 8 | 4,6 | Replaced in 2000, due to difficulties in obtaining replacement parts and service, by an ABB Unitrol static excitation system which is working well. | 10 | 200000 (30) | 20 | 2041 | 2012 | 2012 | Yes | No | 1999 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | Controls | 9 | 4,6 | Replaced in 2000 as part of exciter Controls. Review identified reported difficulties with protective relays calibration drift, and malfunctions and the field flashing maloperation. Subsequently identified as resolved by station. | 10 | 200000 (30) | (2) | 2041 | 2012 | 2012 | Yes | No | 1999 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 10 | 4,6 | Replace with zero PCB when regulations require (2013?) | 10 | 200000 (30) | 3 | 2041 | 2012 | 2012 | Yes | No | 1988 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271312 | 1 | #1 TURBINE & GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | N/A | 11 | 4,6 | Replaced with exciter | 3a | 200000 (30) | 10 | 2041 | 2012 | 2012 | Yes | No | 1999 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR EXCITATION SYSTEM | RT1 RECTIFYING TRANSFORMER | N/A | 12 | 5,6 | Installed in 1969, the unit has a relatively high level of risk due to its age. No details on testing were identified. The units was originally an Askarel oil filled unit but was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. Tests in 2005 identified satisfactory results. The current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry, includes practice for the better management of PCB's in use. | 4 | (45) | 5 | 2041 | 2013 | | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | N/A | 13 | 4 | Hydrogen cooler, hydrogen dryer, and hydrogen purity meter working well. The hydrogen scavenging system (removing entrained hydrogen from the seal oil) appears less effective than the Unit 3 vacuum system. The hydrogen pressure is low, probably due to hydrogen leaks (causes extra heating of the generator core and windings). Consumption is not recorded. The cold gas temperature is low at 30 °C versus GE minimum 35 °C. | 3a | 200000 (30) | (10) | 2041 | 2010 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6806 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 14 | 4 | The horizontal joint of the hydrogen seal assembly was epoxied, to prevent hydrogen/oil leakage into the generator, but the risk is high that the hydrogen sealing system has not been successful in preventing oil entering the generator and contaminating the end-windings. | 4 | 200000 (30) | (10) | 2041 | 2010 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6851 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. CO2 GAS PURGE SYSTEM | N/A | 15 | 4 | Not reviewed in detail. No issues identified except system capacity. | 3a | 200000 (30) | (10) | 2041 | 2011 | 2012 | Yes | No | 2009 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6853 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 16 | 4 | Acceptable condition. | 3a | 200000 (30) | 10 | 2041 | 2010 | 2012 | Yes | No | 1970 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

#### 8.1.1.5 Actions

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

**TABLE 8-2 RECOMMENDED ACTIONS - 6840 #1 GENERATOR STATOR**

| Issues | Recommended Actions |
|---|---|
| 1. There is oil leaking into the stator, reducing the effectiveness of the winding support. Oil and grease has been found on the end-windings at each past inspection, and on other similar GE generators. A leak in the horizontal joint of the seal assembly was found at the last outage and a temporary repair was made – is it still effective 7 years later? | 1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 – 40 kPa (4 and 6 psi).<br>2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator<br>3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness.<br>4. Check the hydrogen consumption and seal oil consumption for leakage. |
| 2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm the condition of the core is sound, before ordering a replacement stator winding for installation in 2012, see next item). | 1. Plan for an El-cid test and a high flux test of the stator core, during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot.<br>2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. Take infra-red photos of the core and note the hot spots (areas greater than 3 °C above the surrounding areas). |
| 3. The GE tests showed the right phase of the stator winding was in very weak condition in 2003. A rewind was recommended. An update on the winding condition should be obtained at the 2012 inspection (preferably from a second source). The tests should only be done on the winding after it has been carefully cleaned and re-tightened, and is known to be clean and dry. | 1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (Check whether the poor insulation condition was due to the high moisture or to the insulation deteriorating during the re-wedging – this is useful information for Unit 3).<br>2. Also test the bushings and the PT's, and carry out ratio tests on the CT's.<br>3. Decide whether the windings will last until 2015, or whether they should be replaced during the 2012 outage.<br>4. Draft a specification now, for the manufacture, test and installation of a replacement winding, together with new RTD's, and bushing and terminal plate flange seals. Also include options for new bushings and CT's, in case they are necessary. This will reduce the outage time, if a winding failure should occur during the next two years.<br>5. At the next major inspection, have the OEM (or potential rewind Contractors) take the stator slot and winding dimensions.<br>6. Consider taking advance delivery of the winding and store it at the plant until needed (make sure the new winding will fit either Unit1 or Unit 2, or identify why this is not possible). |

| Issues | Recommended Actions |
|---|---|
| 4. The end-winding support structure is not able to withstand the operating and system stresses. It loosens and allows the insulation to erode and form grease. An improved end-winding support system is required. | 1. Ask the OEM for an improved end-winding support system to be supplied with the new stator winding (modern techniques are available to allow the supports to slide when hot, rather than develop internal stress that loosens them).<br>2. Have the effectiveness of the new winding installation checked with the “bump” test, and additional support provided where it is found necessary |
| 5. Top ripple springs were installed to increase the time between re-wedging the stator slots. Check that the top ripple springs are still holding the slot parts of the windings firmly in place, and no loosening of the wedges/windings has occurred. | 1. Carry out a wedge tap survey, to check for loose wedges, (and find out whether Unit 2 is likely to require re-wedging at its next major outage). Visually inspect the core teeth for signs of fretting dust or “grease”. |
| 6. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance. | 1. Take Doble test measurements every 2 years, during the summer outage (it is necessary to disconnect the neutral bar – make sure it is replaced carefully, and check the joint resistance with a low resistance meter (“ductor”). |
| 7. A hydrogen seal leak was found at the bushings and at the terminal plate seals. It was sealed temporarily from the inside with RTV. GE recommended the area be checked annually for leaks, but it is not known if this was done. | 1. Replace the bushing seals and the terminal plate seals. This is a difficult and expensive repair that is best done during a stator rewind. RTV sealing of the inside is satisfactory for a short time, but the deteriorated seal usually leaks elsewhere. GE uses viscaseal and a dam to identify a leak, but Hitachi repairs the leak with “titeseal” which is better. |
| **A. Operation** | |
| 1. The stator winding and core RTD’s do not read credible values. They are too low. | 1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase, and the hottest core RTD, on the DCS display. |
| 2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above) | 1. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary. |
| 3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on Units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results. | 1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress.<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line.<br>3. The rotor should be kept in a clean conditions “tent” and air heaters installed to keep the windings warm and dry. |

| Issues | Recommended Actions |
|---|---|
| 4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation. | 1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator. |

**TABLE 8-3 RECOMMENDED ACTIONS - 6839 #1 GENERATOR ROTOR**

| Issues | Recommended Actions |
|---|---|
| 1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 1997. (Defects have been found in other similar rotors after less than 30 years operation). | 1. Remove the retaining rings and the slot wedges<br>2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings. |
| 2. The condition of the end-windings is not known, and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed. | 1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections. |
| 3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings. | 1. Check the insulation blocks and re-place or re-tighten as necessary. (note the dust found probably contains asbestos). |
| 4. The ventilation system of the rotor slots uses sub-slots and radial ventilation ducts. It is prone to axial elongation (creep of the copper and restriction of the ventilation holes. | 1. Check the radial holes near the ends of the rotor body for restrictions, and record the restrictions, for future (the rotor should be re-wound when the restriction exceeds 25 % of the hole area).heck the sub-slots for oil, dirt and accumulated debris. Vacuum/blow out as much of the dirt as possible. |
| 5. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time. | 1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load.<br>2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights.<br>3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection. |

| Issues | Recommended Actions |
|---|---|
| 6. There is no record of the generator bearings being re-metalled, but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective. | 1. Re-furbish both generator bearings.<br>2. NDE the bearing Babbitt for good bond with the shell.<br>3. Check the surface for even wear<br>4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually.<br>5. Replace if defective. Replace oil deflectors. |
| 7. GE recommended that spare bearing thermocouples be held in stock in case the installed thermocouples fail in service. | 1. The bearing thermocouples are old, and in dubious condition. New thermocouples should be installed at the next major outage. |
| 8. A week was spent working on the hydrogen seals, and numerous problems were encountered. The hydrogen seal clearances on the hydrogen side were reduced to the low end of the clearance, in an attempt to prevent oil leaking into the generator. An oil leak from the horizontal joint of the hydrogen seal was found at the CE and repaired temporarily with epoxy | 1. Replace the insulation plates of the CE seals. Check the titeseal groove at the upper and lower CE end-shield for leaks. Air-test the generator for leaks, and fix them properly at the next major inspection. A new hydrogen seal assembly should be considered for the CE end. |
| **A. Operation** | |
| 1. The field current is not credible, it is much too low. | 1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter. |
| 2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation). | 1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or - obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display. |
| 3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound). | 1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core. |
| 4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation). | 1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft.<br>2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or<br>3. Install a Shore grounding brush and shaft current and voltage monitoring system. |

| Issues | Recommended Actions |
|---|---|
| 5. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on Units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results. | 1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress.<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry. |

**TABLE 8-4 RECOMMENDED ACTIONS – 6850 #1 HYDROGEN SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. Several problems were found with the float trap of the middle de-training tank of the seal oil system. The valve disc had hardened, the level control was incorrect, and the valve was installed backwards. | 1. Replace the seals, and viton disk, and gaskets, and check the operating level in the tank at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures.<br>2. GE recommends the seal oil supply piping be flushed annually, to prevent dirt in the emergency by-pass line entering the system. |
| 2. The seal oil vacuum pump is a high maintenance item. It has a rotary valve that needs to be replaced at each inspection. | 1. Purchase a spare rotary seal and install it at the next major inspection. Carry out preventive maintenance on the pump |
| 3. The hydrogen coolers were leak tested and found satisfactory, but GE recommended the gaskets be replaced at each major inspection. | 1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!) |
| 4. The liquid leak detector valve had incorrect flanges and gaskets and is prone to failure. | 1. Check the operation of the liquid leak detector relay, and service the parts. |
| 5. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater. | 1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, and check for hydrogen leaks, especially at the purity meter and sampling valves. |
| 6. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve. Locate and repair hydrogen leaks ASAP. |
| **A. Operation** | |
| 1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings. | 1. Locate and repair the hydrogen leaks.<br>2. Increase the hydrogen pressure to 207 kPa (30 psi). |

| Issues | Recommended Actions |
|---|---|
| 2. The hydrogen consumption of each generator is not recorded. | 1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded. |
| 3. The cold gas temperature is low at 30 °C, GE usually recommend a minimum of 35 °C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging. | 1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched.<br>2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched. |
| 4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected. | 1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating. |
| 5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve.<br>2. Locate and repair hydrogen leaks ASAP. |

**TABLE 8-5 RECOMMENDED ACTIONS - 6849 #1 EXCITATION SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. The ABB static excitation system is reported to be operating satisfactorily. However, the controls and protective relays are prone to calibration drift, and malfunctions. The field flashing can maloperate | 1. Check the operation of the excitation system controls, limiters and protection relays.<br>2. Check the field breaker contacts and operation.<br>3. Check the thyristors and heat sinks, and snubbers, for signs of overheating, |
| 2. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing, -the risk of generator damage is highest during initial energization on AVR control. | 1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs. |

### 8.1.1.6 Actions - Unit 1 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

**TABLE 8-6 RECOMMENDED ACTIONS – UNIT 1 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6696 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | N/A | 1 | 4 | Reduce operating intervals between major outages to 6 years. | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 2 | 4 | NDE inspection of the rotor high-stress areas should be done in 2012 - cover the retaining rings, changes in cross section of the rotor (journals and coupling etc), the rotor tooth dovetails, the slot wedges and the lead wedges for fretting fatigue cracks, the rotor core (bore sonic inspection), the bearing shells for babbitt bond, the fans for fatigue cracks. The rotor dovetails with short steel wedges should be checked carefully, due to the higher risk of a fatigue crack developing under the high cyclic bending stress. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 3 | 4 | Remove the retaining rings and the slot wedges to permit a closer inspection. Surface defects may be found in the retaining rings, a fatigue crack may exist in the dovetails, spitting damage may be found at the wedge ends, due to negative sequence current. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 4 | 4 | Install a rotor flux probe near the turbine end of the stator bore wired out through the existing IRIS penetration and junction box to detect the presence of shorted field turns. Usually precedes development of a rotor ground fault and that the field winding has suffered extensive copper deformation and weakening of the turn insulation, and is close to the end of its useful life. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 5 | 4 | Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 6 | 4 | Monitor the shaft ground current, or the shaft voltage at the outboard end of the generator - replace the original equipment with on-line monitoring capability. The risk of a shaft current flowing through the bearing or hydrogen seal increases during synchronous condenser operation. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 7 | 4 | Perform annual 500 volt megger checks on the rotor, to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms). | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 8 | 4 | Install a field winding temperature indicator in control room. | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 9 | 4 | Repair hydrogen leak in the bushing box horizontal joint of the cover plate holding the bushings bushing seals. Difficult as it necessitates breaking the main connections, dropping the bushings, installing the gaskets, and re-installing the bushings. May be necessary to remove the whole bushing box. An alternative repair of poorer integrity is to seal the inside joint flanges around the bushings and terminal plates with RTV sealant. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 10 | 4 | Install a hydrogen consumption “totalizer” in each hydrogen supply line for recording daily and checked for leaks. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 11 | 4 | Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height and alignment of the rotor, which can increase the bearing vibration levels. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 12 | 4 | Before implementing a stator rewind, perform a flux loop test and thermal imaging of the core to detect any hot spots and repair them before installing the new winding. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 13 | 4 | Perform a minor inspection and Doble test after 4 or 5 years, and carefully monitor the on-line partial discharge monitoring. | 2016 | 2 |

Table 8-6 Cont’d

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 14 | 4 | Take partial discharge activity readings in the slot portion of the windings and in the end-winding portion during normal service conditions. Work with IRIS on a priority basis to repair so that the results are available in time to consider replacing the windings during the 2012 outage. Detect de-lamination of the insulation tapes, deterioration in the low-resistivity paint at the outer surface (ground wall) in the slots, and discharges in the end-windings. | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 15 | 4 | Repeat the DC hipot test at the next major inspection, taking extra care to ensure the insulation is dry before the test. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 16 | 4 | Perform an intermediate inspection of the stator end-windings after 4 years to establish the presence of oil and grease on the end-windings to better establish the timing of the next major inspection. | 2016 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 17 | 4 | Proceed with planning work for a rewind now - typically requires 9 to 12 months to plan and carry out a stator rewind, plus site work of 4-6 months. | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 18 | 4 | Proceed with the installation of a new stator winding at the next major outage in 2012. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | N/A | 19 | 4,6 | Upgrade static exciter controls compatible with the latest Unitrol 6000 system. | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | N/A | 20 | 4 | Install a hydrogen consumption “totalizer” in each hydrogen supply line, for recording daily and checked for leaks. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 21 | 4 | Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. CO2 GAS PURGE SYSTEM | N/A | 22 | 4 | No action recommended. | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 23 | 4 | Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels. | 2011 | 1 |

### 8.1.1.7 Risk Assessment

Table 8-7 below illustrates the risk assessment for the Unit 1 generator, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-7 RISK ASSESSMENT – UNIT 1 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | N/A | 5 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Forging and Field Windings | 6 | 4 | Electrical Failure - EOL. | 10+ | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Plan for a rotor rewind by 2020. Evaluate techno-economic values of early implementation in 2015 as part of synchronous condenser conversion. |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Forging and Field Windings | 7 | 4 | Mechanical failure retaining rings. | 10+ | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Removal of the retaining rings and inspection in 2012. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame | 8 | 4 | Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse). | 15 | None | 3 | C | Medium | 3 | C | High | Loss of unit generator and SC capability. Potential serious injury situation | V/f element of the new generator multi-functional relay be set up to provide back-up V/f protection beyond standard protection against over-fluxing by the volts/hertz relay. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame | 9 | 4 | Mechanical damage - inspection related. | 15 | None | 2 | B | Low | 2 | B | Low | Damage is local | Repair during outage. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame | 10 | 4 | Mechanical - Loose plates vibrating in the magnetic field then break off and damage the stator winding. | (5) | None | 3 | C | Medium | 3 | B | Medium | Loose plates break off and damage the stator winding. | Check for signs of red iron oxide dust in the stator bore and confirm by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame | 11 | 4 | Electrical - failures of the stator winding, and/or poor stator winding ground protection. | (10) | None | 3 | D | High | 3 | C | High | Damage to stator core | 2012 Inspection and repairs - stator rewind. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings | 12 | 4 | Electrical - insulation/winding failure - system over-voltage transients. | (2/8) | None | 3 | D | High | 3 | C | High | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing, and cannot be considered to be reliable. | Rewind of stator in 2012. Evaluate techno-economic risk of deferral to 2018 as soon as possible. (Currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate surges, or upon the statistical unlikelihood of the worst over-voltage situation occurring. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings | 13 | 4 | Mechanical/electrical - glued layers of mica flake insulation open | (2/8) | None | 3 | D | High | 3 | B | Medium | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing, and cannot be considered to be reliable. | Rewind of stator in 2012. Evaluate techno-economic risk of deferral to 2018 at next recommended overhaul. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings | 14 | 4 | Mechanical/electrical - end-windings loosen. Line-end coils & phase leads distort and fail during system fault condition. | (2/8) | None | 2 | D | Medium | 2 | B | Low | The line-end coils and phase leads are at most risk, of distortion, and could fail during a severe or a sustained system fault condition. | Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind. |
| 1296 | 6690 | 6691 | 6696 | 6840 | 7345 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. STANDOFF INSULATORS | N/A | 15 | 4 | Mechanical vibration & electrical fault greasing. | 20 | None | 2 | D | Medium | 2 | B | Low | Loss of unit generator and SC capability. Potential serious injury situation | Replacement. Reduce stator vibration. |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | Static Exciter | 16 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 2 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to Unit | Inspect and Test per current maintenance program. |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | Static Exciter Controls | 17 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | (2) | None | 2 | C | Medium | 3 | A | Low | Loss 1 unit generation. Damage to Unit | Upgrade controls for compatibility by 2013. |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITATION TRANSFORMER | N/A | 18 | 4,6 | Regulatory PCB. | 3 | None | 3 | C | Medium | 2 | B | Low | Oil spill/PCB contamination | Replace per regulations when required. |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271312 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER FIELD BREAKER | N/A | 19 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 1 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to Unit | Inspect and Test per current maintenance program. |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen Pressure Control | 20 | 4 | Mechanical/electrical fire. | 2 | None | 3 | C | Medium | 3 | D | High | Seal Leak, Hydrogen Fire/Expl - oil leaks into the stator if the flow rate is too high, and overheating and failure of the hydrogen seals if the flow rate is too low. | New hydrogen seals and totalizer. |

Table 8-7 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen System - Purity meter and Dryer | 21 | 4 | Electrical/fire | 2 | None | 1 | C | Low | 1 | D | High | Hydrogen Fire/Explosion | Recent replacement - monitor condition and maintain. |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6806 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | | 22 | 4 | Mech - loss, spill - hydrogen leak. | 10 | None | 1 | C | Low | 2 | C | Medium | Hydrogen Fire/Explosion | Inspect and Test per current maintenance program. |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6851 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. CO2 GAS PURGE SYSTEM | CO2 Supply, Purge System | 23 | 4 | Mech failure. | 30 | None | 1 | C | Low | 2 | C | Medium | Hydrogen Fire/Explosion | Inspect and Test per current maintenance program |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6853 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | Auxiliaries - Hydrogen Coolers | 24 | 4 | Electrical/fire. | 10 | None | 1 | C | Low | 1 | C | Medium | Hydrogen Fire/Explosion | Monitor condition and maintain. |

### 8.1.1.8 Life Cycle Curve and Remaining Life

Figures 8-2 and 8-3 below, illustrate the life cycle curve for the Unit 1 generator system. It is broken into two parts – the generator and the exciter. Differences in the scenarios in Section 6 do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically thirty years and 200,000 to 240,000 operating hours to forty years and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode (beginning in 2015), as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and much of the hydrogen system are the same age. The new parts of the hydrogen system are not identified due to their shorter time in-service. One vertical line illustrates the timing of the next generator overhaul in 2012. The lowest two horizontal lines represent the ranges of expected generator life for Holyrood Unit 1 based on current and historical information and expert opinion. The “Rewind Unit 1 Recommended” line is based on the recommended estimated remaining reliable stator winding life of five years at current generation levels. The two upper lines also represent an assessment of a longer 10 + year of the lower reliability, higher failure risk, remaining life of the rotor winding as well as a maximum 20 years likely for the stator and rotor cores.

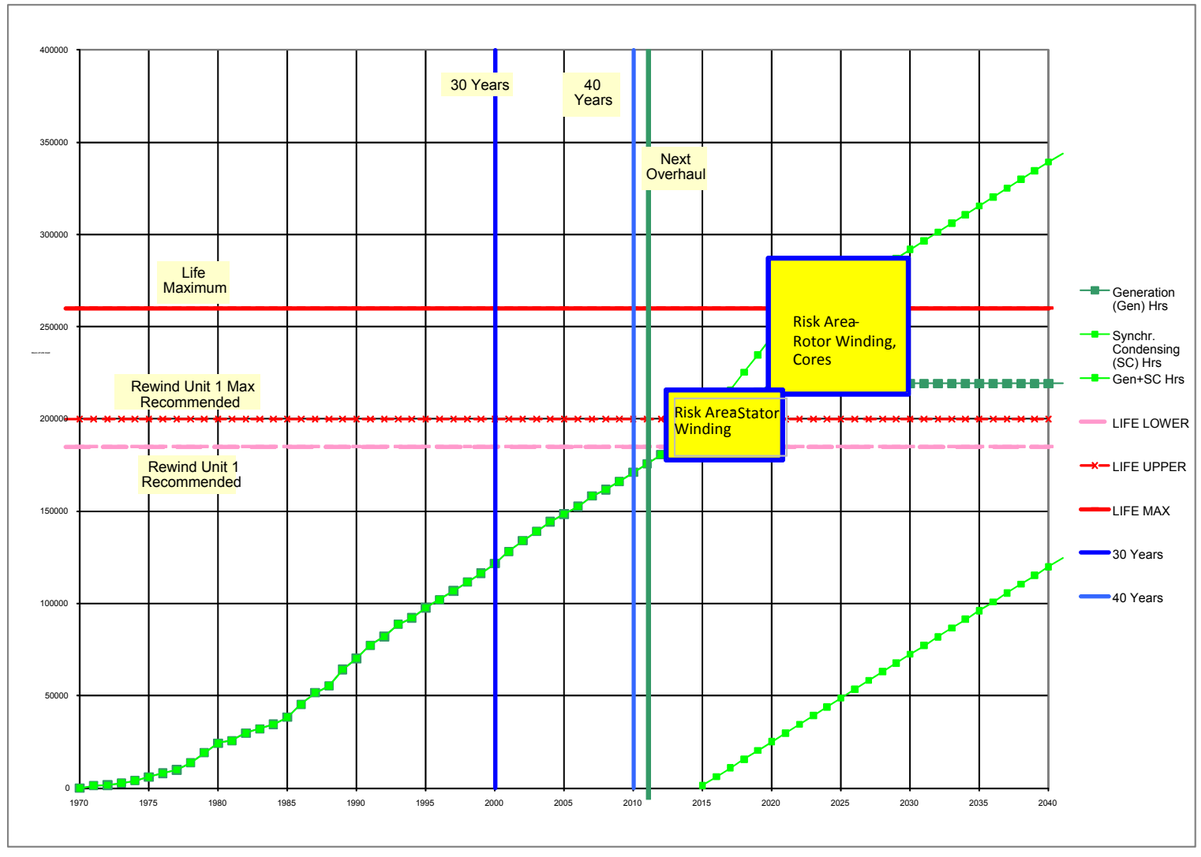



**FIGURE 8-2 LIFE CYCLE CURVE – UNIT 1 GENERATOR**

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode (beginning in 2015). It has two curves for any remaining original equipment as well as for the upgrades to the system made in 2001.

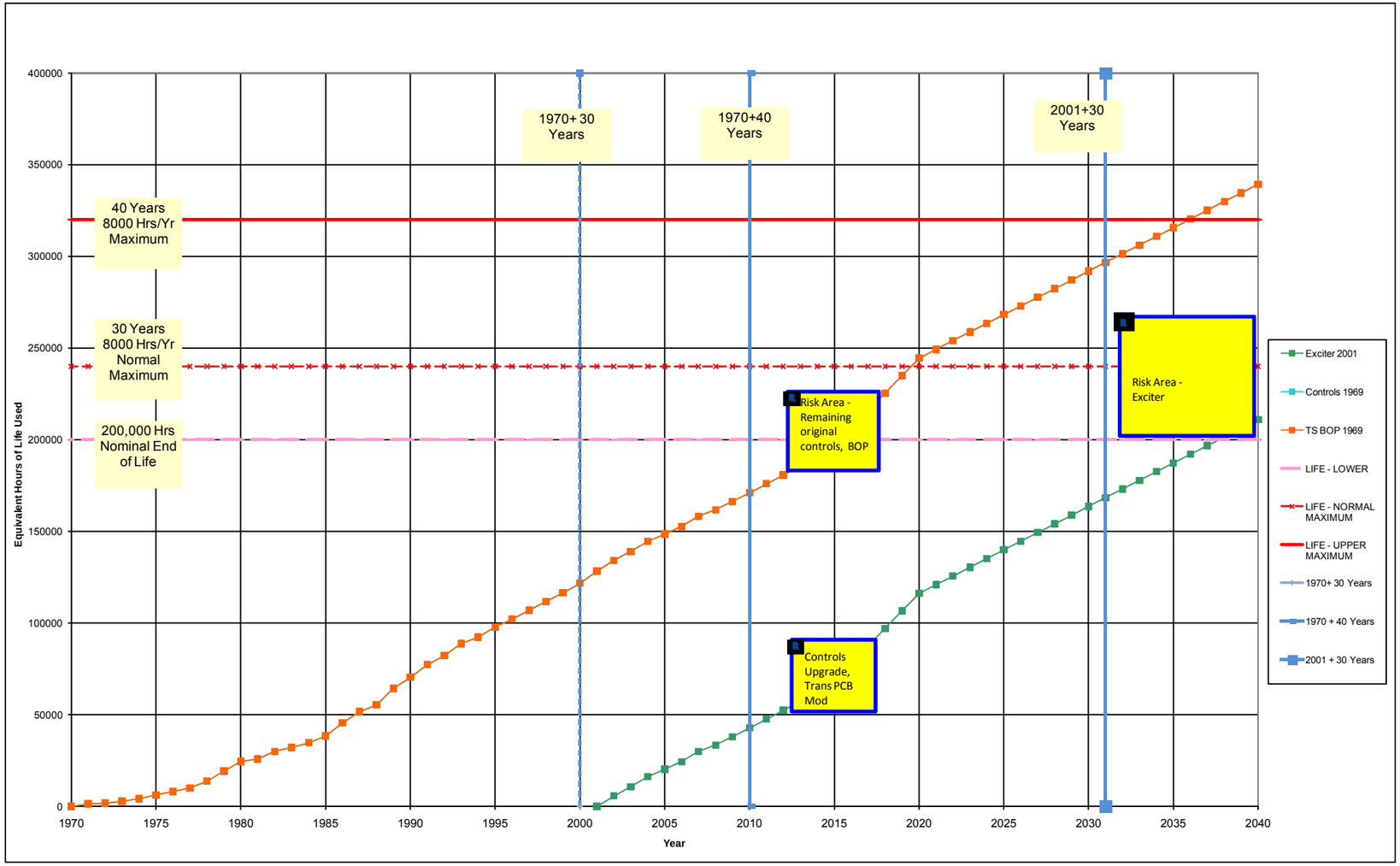



**FIGURE 8-3 LIFE CYCLE CURVE – UNIT 1 GENERATOR - EXCITER**

The curves indicate that the remaining life (RL) of the Unit 1 generator exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2012 overhaul to demonstrate the ability to meet the 2041 EOL date. The exciter should for the most part be able to meet an EOL of 2020, and with periodic refurbishment may meet 2041.The highlighted nearer term risk areas include the stator winding, exciter controls (upgrade only), the rectifying transformer, and some original BOP components. These systems are candidates for replacement or refurbishment – addressed in later sections. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator's life and should be a six year cycle.

### 8.1.1.9 Level 2 Inspections – Unit 1 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided that the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by the Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of steam turbine and generator inspections. This nine year interval between major overhauls is considered excessive, given the age and condition of the generators. A return to a six year interval is considered necessary.

**TABLE 8-8 LEVEL 2 INSPECTIONS – UNIT 1 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | None | 0 | 4 | Level 2 "Pre-Major Outage Inspection" Work Allowance. | 2011 | 1 | $100 |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | None | 1 | 4 | No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes:<br>- Review generator drawings, contract information, and operating manual to clarify design details.<br>- Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound.<br>- Stator Winding: Obtain Doble test data and on-line partial discharge measurements. | 2012 | 1 | $1,849 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | None | 2 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | None | 3 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6840 | 7345 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. STANDOFF INSULATORS | None | 4 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | None | 5 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITATION TRANSFORMER | None | 6 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271312 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER FIELD BREAKER | None | 7 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | None | 8 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6806 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | None | 9 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6851 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. CO2 GAS PURGE SYSTEM | None | 10 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6853 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | None | 11 | 4 | Included above. No Level 2 required prior to overhaul. | 2012 | | |

#### 8.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 Generator Outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2012, AMEC recommends that those items that would assist in better preparing for the 2012 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2012 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

**INSPECTIONS**

**Inspections – External Components:** The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range);
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

**Inspection – Stator Internal Components:** The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure - compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing;
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind;
- Winding TC's – inspect and check for function.

**Inspection – Stator Core:** The following stator core items could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

**Inspection – Stator Windings:** The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism);

**Inspection – Phase Bus Connectors and Terminals:** The following could be inspected with the Stator Core (Rotor In) to **the** Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

**Inspection - Hydrogen Coolers:** The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

**Inspection – Rotor:** The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition (including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

**Inspection – Auxiliaries:** The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

**TESTS**

**Test – Stator:** The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
    - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
    - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

- A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
- DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen;
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

**Test – Rotor:** The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum .
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;
  - Shorted turns Detection;
  - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise);
  - Hydrogen Seals: NDE - Megger seal insulation; and
  - Bearings: Megger bearing insulation.

### 8.1.1.11 Capital Program Suggestions

Table 8-9 below shows the suggested typical capital enhancements that should be considered for the Unit 1 generators:

**TABLE 8-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | N/A | 1 | 4 | See details below. | 2012 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6839 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 2 | 4 | No capital required. | | |
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 3 | 4 | Recommend ordering Stator windings in 2011 for rewinding Stator in 2012. Installation in 2012 subject to techno-economic optimization results. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6840 | 7345 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. STANDOFF INSULATORS | N/A | 4 | 4 | No capital required. | | |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | N/A | 5 | 4,6 | Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system. | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITATION TRANSFORMER | N/A | 6 | 4,5 | Replace rectifying transformer. | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271312 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER FIELD BREAKER | N/A | 7 | | No capital required. | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | N/A | 8 | 4 | Install hydrogen consumption “totalizer” in each hydrogen supply line. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6806 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 9 | 18 | Replace/overhaul seal oil skids required for SC operation. | 2015 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6851 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. CO2 GAS PURGE SYSTEM | N/A | 10 | | No capital required. | | |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6853 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 11 | 4 | No capital required. | | |

### 8.1.2 Asset 6805 – Unit 1 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

| | |
|---|---|
| Unit 1: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6691 #1 Turbine & Generator |
| Sub-Systems: | 6805 #1 Turbine Lubricating Oil<br>6807 #1Turbine Hydraulic Oil Systems |
| Components: | 6803 #1 Tank & Equipment<br>6804 #1 Purification<br>6829 #1 Pump South<br>6830 #1 Pump North<br>6833 #1 DC Pump<br>6835 #1 Hydraulic Oil Pump North<br>6838 #1 Hydraulic Oil Pump South |

#### 8.1.2.1 Description

The generator lube oil system is integrated into the steam turbine system. It consists of a storage system, AC and DC pumping systems, filtration, and heat exchangers. The lube oil tank holds approximately 98400 L (2600 US gallons) of Turboflo R&O 32 lubricating oil. Within the lube oil tank, there are three pumping units (two 100% AC motor driven and one 100% DC motor driven) and three 100% duty lube oil heat exchangers. The system supplies 35-45 °C oil to the turbine/generator lubrication and hydrogen seal oil systems. Pump discharge pressures at 275 – 300 kPa would be normal.

Lubricating oil heat exchanger cooling water heads can be isolated and removed for easy cleaning. An oil purifier is connected to the oil tank through a separate piping arrangement and is used primarily to remove water from the oil which accumulates because of the condensation throughout the process. The system is fitted with two 100% duty oil filters insuring heavy particles in the oil are removed and do not reach the bearings during lubrication.

Two 100% positive displacement hydraulic oil pumps are used to operate the emergency stop valve, the combined intercept reheat stop valves, the control valves and other miscellaneous valves on the steam turbine. The pumps operate at a pressure of 15.5 MPa to counteract the large springs which normally hold the valves closed. The hydraulic oil system has its own network of high pressure piping external to the lubricating oil system which makes it somewhat easier to maintain if problems occur.

#### 8.1.2.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2012 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 166 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 210 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 219 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 219 | 120 |
| Starts Actual - Ops to Dec 2009 | 482 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 714 | 130 |

#### 8.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in very good condition as part of the plant's normal maintenance and inspection program and is examined as well during major generator inspections.

### 8.1.2.4 Condition Assessment

This system has been in service since the unit was placed in service in 1970. Although the lubrication system is critical to the operation of the steam turbine/generator and may cause a short unit shutdown in the event of a failure, a longer shutdown may occur due to a failure of the lubricating oil piping system which cannot be inspected easily because the supply piping is installed inside of the oil return piping which is connected to the oil storage tank.

The oil storage tank appears externally to be in good condition. Internal inspection reports were not available at this time. Failures of any of the oil pumps or the oil purifier are easily repaired and, barring no hidden problems, this system should continue to operate for the time frame required. If this unit is required to support synchronous condenser operation after generation mode, this system will be required to operate at all times and should not present any major issue.

All parts of the generator lube oil system are expected to be able to make their next inspection date. All are expected to undergo more rigorous evaluation at that time. Most will be able, with maintenance and replacement, to meet the generation end date of 2020. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

**TABLE 8-10 CONDITION ASSESSMENT – UNIT 1 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 6695 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 27 | 18 | Generally good condition. | 3a | 200000 (30) | 10 | 2041 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 28 | 18 | Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired. | 3a | 200000 (30) | 10 | 2041 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 29 | 18 | Lube oil tank appears to be in good condition. Internal inspection reports were not available. | 4 | 200000 (30) | (10) | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | N/A | 30 | 18 | Lube oil purification system is relatively new and in good condition. | 3a | 200000 (30) | 10 | 2041 | 2011 | 2012 | Yes | Yes | 2001 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 lube oil system.

**TABLE 8-11 RECOMMENDED ACTIONS – UNIT 1 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 6695 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 55 | 9 | Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year. | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 56 | 9 | Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year. | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 57 | 9 | Perform Level II inspections on oil storage tanks and internals. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | N/A | 58 | 9 | No action recommended. | | |

### 8.1.2.6 Risk Assessment

Table 8-12 below illustrates the risk assessment for the system, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-12 RISK ASSESSMENT – UNIT 1 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Tanks | 50 | 9 | Corrosion, erosion. | 10+ | None | 1 | A | Low | 1 | A | Low | Oil leak – containment overflow. | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Pumps & Motors | 51 | 9 | Mechanical and/or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Pumps & Motors | 52 | 9 | Bearing Damage - duty on the starting equipment, during synchronous condenser operation | 10 | None | 1 | A | Low | 1 | C | Low | Unit shutdown – multiple systems. | Maintain and inspect full-flow filter and by-pass to reduce the risk of bearing damage. |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Coolers | 53 | 9 | Mechanical failure/leaks. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | Lube Oil Filters | 54 | 9 | Mechanical and/or pluggage failure - water and particulate | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Inspect and maintain. |

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

### 8.1.2.7 Life Cycle Curve and Remaining Life

Figure 8-4 below illustrates the life cycle curve for the Unit 1 generator lube oil system. Two curves are required given that the upgraded purification system entered service in 2001, while other major elements of the lube oil system are largely of the same age. There is insufficient information to develop specific accurate curves for the storage tank, and coolers. Further detailed examination during the 2012 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing model on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

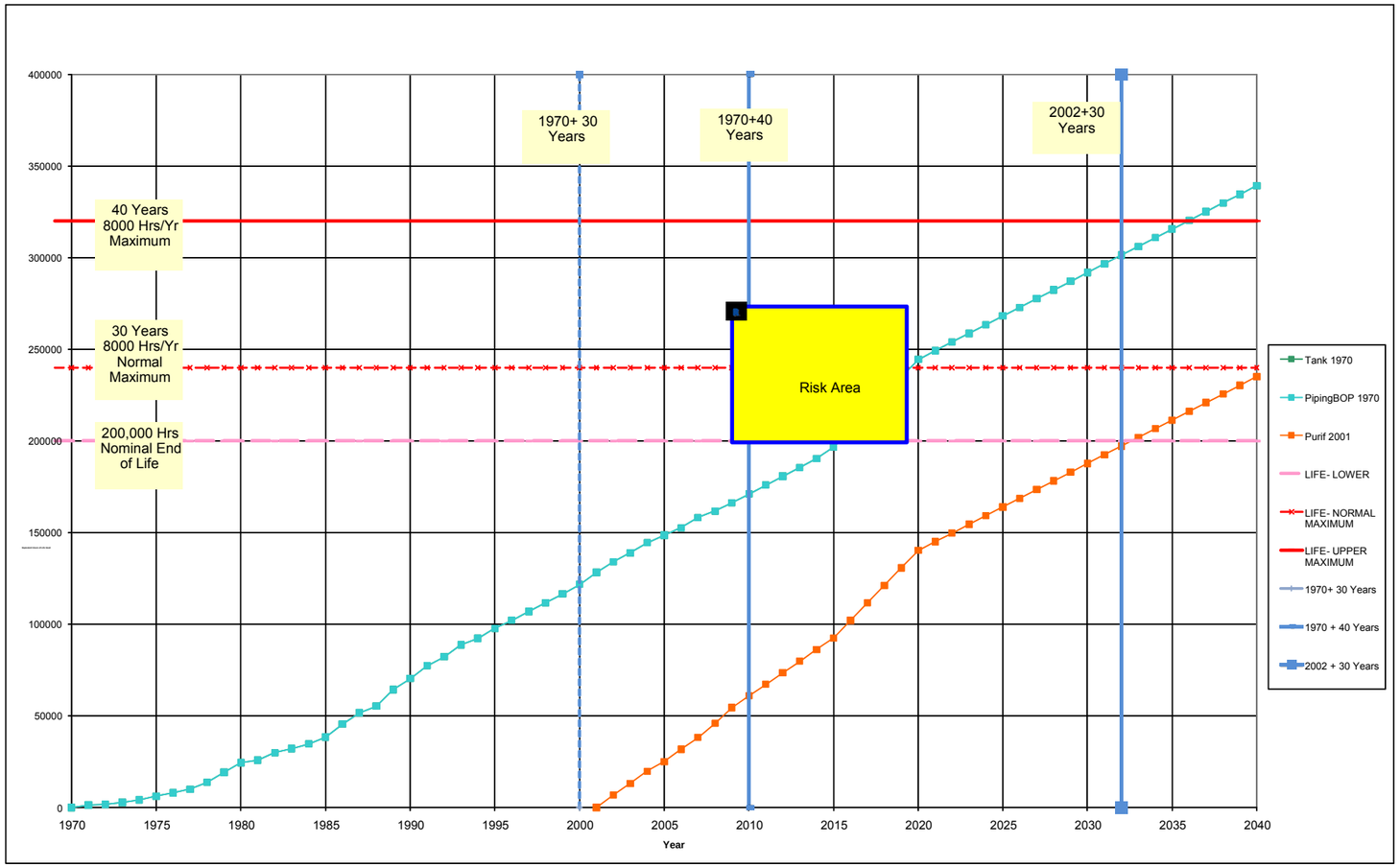



**FIGURE 8-4 LIFE CYCLE CURVE – UNIT 1 GENERATOR LUBE OIL SYSTEM**

The curves indicate that the remaining life (RL) of the Unit 1 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired end of life (EOL) date of 2041. Thus no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2012 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011, albeit of a modest level and lower priority. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2012 turbine generator overhaul. The 2012 overhaul/inspection is a fundamental element in changing the current assessment.

### 8.1.2.8 Level 2 Inspections – Unit 1 Generator Lube Oil System

Given the condition historical data reviewed, a Level 2 analysis of the lube oil storage tank is recommended. No other Level 2 analyses is required, provided the current inspection and maintenance program for the system is maintained and a more detailed inspection is performed at the turbine overhaul.

**TABLE 8-13 LEVEL 2 INSPECTIONS – UNIT 1 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 6695 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE OIL SYSTEMS | None | 38 | 9 | See details below. | | | |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | None | 39 | 9 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | None | 40 | 9 | NDE inspection and visual inspections of lube oil tanks and internals. | 2011 | 2 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | None | 41 | 9 | No Level 2 required. | | | |

### 8.1.2.9 Capital Projects

The suggested capital enhancements include:

**TABLE 8-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 6695 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 22 | 9 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 24 | 9 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | N/A | 25 | 9 | Replace turbine lube oil conditioners. | 2013 | 1 |

### 8.1.3 Asset 6723 – Unit 1 Electrical and Control Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the electrical and control systems associated with Unit 1 are as follows:

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 6723 #1 Electrical & System & Controls |
| Sub-Systems: | 6723 #1 Electrical & System & Controls |
| Components: | 6721 #1 Relay Room Protection & Control<br>6722 #1 Main Controls<br>6724 #1 Generator Bus-Duct and Connections<br>6728 #1 Battery Chargers<br>7184/7186/7187 MCC's, C2, C3, C4<br>7193 #1 UPS1 Inverter<br>270151 #1Turbine Supervisory System<br>270295 #1Switchgear, 4160V/600V<br>7182 #1 Power Centre "A" UAB1, (600V)<br>291668 #1 DCS<br>**COMMON SYSTEMS**<br>270297 Control Cables<br>270298, Power Cables<br>600V Metric Plugs |

#### 8.1.3.1 Description

**Asset 6721 Unit 1 Relay Room Protection & Control**

Generator G1, Transformer T1 and Auxiliaries P&C Panels, were manufactured by Canadian General Electric, and installed in 1969.

**Generator 1 and Transformer T1 Protection Panels:** These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show annunciation and T1/UST1 gas and winding temperature trips and indications.

**Unit 1 Protection Auxiliary Panel:** This panel shows DC buses indications and blocking switches.

**Unit 1 Metering Panel:** This panel shows Generator 1 and Static Exciter 1 WHR's, runtime, flexitests and stator ground fault protection added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

The rear of the panels show the original GE and Brown Boveri Control relays, Agastat timers and transducers.

**Station Service Transformers UT1 and UT2 Protection Panels and Gas Turbine Metering and Protection Panels:** These panels utilize GE electro-mechanical relays and blocking switches. In addition they show annunciation and SST1/SST2 gas and winding temperature trip indications.

**Unit 1 Services Protection Panel:** This panel shows UT1/SST/UT2 MWatts, WHR's, DC buses indications, voltages and blocking switches.

**Gas Turbine Metering and Protection Panel:** This panel includes relaying for differential, WHR, neutral over-current, annunciation and blocking switches.

**Asset 6722 Unit 1 Main Controls**

The original Unit 1 Main Controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments, and Panalarm annunciation. Modifications have been made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation. In addition, a newly commissioned auto-synchronizing system has been added for automatically synchronizing Unit 1 to the Island Grid via the GE Speedtronic Mark V turbine control system. This allows the operator to select the U1 breaker and activate the Mark V synch. control, which incorporates a 25C synch. check function to permit placement of U1 on the grid.

G1, MW, Amps, MVA's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Screens and keyboards are provided to include control, indications, and annunciation of unit functions with boiler purge to be included in Sept. 2010.

Original controls, located in the console desk include the following. Circulating pumps, cooling water pumps and valves, thermo probe, AC and DC oil pumps, extraction and hydraulic pumps, Vacuum pumps, speed load and load limit, AVR set-point and selection.

Unit 1 trip and raise/lower volts and Unit 1 Turbine Trip pushbutton.

One screen and keyboard is provided for common indications.

The original manually operated switches and indications remain for synchronizing and operation of breakers B1B11 and B1L17. See auto synch. modifications above.

Original common analog instruments, for Unit 1 and Unit 2, (Stage 1), indicate incoming and running volts, incoming and running frequencies, and synchronizing.

Unit 1 relaying and transducers are situated in the Unit 1 logic cubicles behind Unit 1 control room. Relays are Struthers & Dunne with Agastat timers.

Other Information: Common screens and keyboards are provided to monitor and control the 4160/600V bus system via the DCS, and indicate, station service current alarms, D1 and D2 diesels control and indications, system frequency and the 4160/600V bussing, including gas turbine.

**Asset 6724 Unit 1 Generator Bus-Duct and Connections**

The generator bus-duct is a 3 phase Isolated Phase Bus complete with PT's and Neutral Cubicle manufactured by ITE and installed in 1969.

**Asset 6728 Unit 1 Battery Chargers**

Units 1/2, 129VDC Battery Charger 1, manufactured by Primax Technologies Inc. and installed in 2006. Charger 1 is a type P4500F-3-125-60, 575V Input, 129VDC Output, max. charger output rated 60A.

Units 1/2, 129VDC Battery Charger 2, manufactured by Staticon and installed in 1969.

Charger is original. A new Primax Charger was installed in 2010(Similar to Charger 1 above).

Unit 1, 258VDC Battery Charger, manufactured by CIGENTEC Inc. and installed in 2001. Charger is a type C3-250-200PAF3BHRGCUOD3S2X9, 600V Input, 258VDC Output, max. 200A Charger rated maximum output.

Reference Holyrood Plant Charger Database. Last equipment check 04 Feb 2010.

Other information:

Unit 1, 258VDC Panel was manufactured by Westinghouse, installed in 1969, and is a type CDP, complete with Westinghouse breakers.

**Assets 7184/7186/7187, MCC's, C2, C3, C4**

Reference the Stantec Report – Holyrood Generating Station MCC Assessment, dated January 15, 2009, for details regarding the MCC's.

**Asset 7193 Unit 1, UPS1 Inverter**

Inverter UPS1 was manufactured by Eaton Powerware, Series 9315 and installed in 1997. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77°F (25°C).

Other Information: The 120/208V, 3 phase Distribution Panel-boards fed from UPS1 inverter, via Distribution Splitter are as follows:

- Unit 1 UPS Panel No.1 at Col L10, El 24'-2", fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, branch breakers type BQ, and was installed in 1998.
- Unit 1 UPS Panel No.1/A at Col L10, El 24'-2", fed from Panel No.1. Siemens, Type P1, 3 phase, 4W, 250A, 42 circuit, branch breakers type BL, and was installed in 1998.
- Unit 1 WDPF Panel,DP-1 relay room, fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, branch breakers type BQ, and was installed in 1998.

**Asset 270151 Unit 1 Turbine Supervisory System**

The turbine supervisory system was manufactured by Bently Nevada and installed in 1990. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

The functionality of the Bently Nevada system has been partially transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevada, and is transferred via a DDX link to the instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 1 mechanical protection.

**Asset 270295 Unit 1 Switchgear 4160V/600V**

Unit Board UB1 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear, utilizes original draw-out power, air-magnetic breakers, Type 5HK, 1200A and 2000A. All protection, synch, and control relays are original CGE electro-mechanical. Schweitzer 701, Motor Protection Relaying is used on U1 Circulating Water Pumps and North and South Condensate Extraction Pumps. All other loads utilize the original P&B Golds relays.

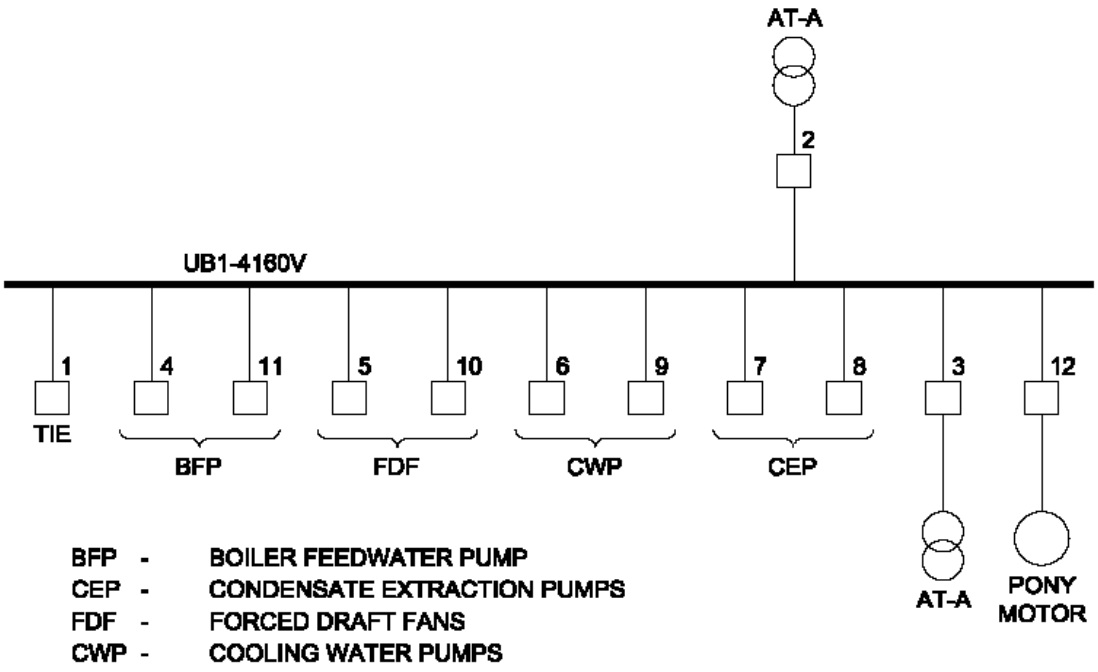



FIGURE 8-5 UNIT 1 UB1 SWITCHGEAR

**Asset 7182 Power Centre "A" UAB1, (600V)**

The unit was manufactured by CGE and installed in 1968. The switchboard utilizes CGE AK-50 Incoming/ Tie Breakers, and CGE AK-25 Feeder air-circuit breakers. The Unit Aux. Transformer, AT-A, is a Westinghouse, 1500kVA, 4160V:600/347V, complete with primary taps.

**Asset 291668 Unit 1, DCS**

The DCS was manufactured by Foxboro, and is an Invensys system installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling installed at that time. Original system was hard-wired, but later updated to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004. The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2;
- IACC, Version 2.3.1 (Configuration Program); and
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program).

Reference: Foxboro Drawing D545390-SA-001 in station files for system configuration.

#### 8.1.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Replaced (DCS) | 2004 |
| Replaced Exciter | 2000 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |

#### 8.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 8.1.3.1 Description and in 8.1.3.4 Condition Assessment.

### 8.1.3.4 Condition Assessment

The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined about every five years or so. The areas of most concern are the exciter controls and protection and motor controls, which have in fact been identified by the plant as an area in need of upgrade in the very short term. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring needs replacement or refurbishing. The condition assessment for the various systems is presented in the following table.

**TABLE 8-15 CONDITION ASSESSMENT - UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 276 | 6 | N/A | | | | | | | | | |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | N/A | 280 | 6 | Generator & Transformer & Auxiliary Protection and Metering Panels tests in 2005 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2011, 2017, 2023, etc.). | 10 | (40) | 10 | 2041 | 2011 | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | N/A | 281 | 6 | Station Service UT1 and UT2 Protection and Gas Turbine Metering and Protection Panels and Unit 1 Services Protection Panel tests in 2006 were satisfactory Some ingress of dust and foreign material. Testing conducted on a 6 year cycle *(2012, 2018, 2024, etc) Gas Turbine Metering and Protection Panel tests (GT Protection, Transformer T9 Protection and GT Sync) in 2008 were satisfactory. Some ingress of dust and foreign material. Testing on a 6 year cycle (2014, 2020, 2026, etc.) | 10 | (30) | 10 | 2041 | 2014 | | No | No | 1970 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 282 | 6 | Breaker overhauls have been carried out, between 1995 and 2007 (See Appendix). All 4160V switchgear is applied within ratings. Overhauls due. Past normal life, extended by overhauls/maintenance. | 10 | (25-30) | 5 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 283 | 6 | There are age and spares problems with the relaying system. | 4 | (30) | 10 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DCS | DCS | N/A | 284 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 10 | 2041 | | | Yes | No | 2004 |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | N/A | 285 | 6 | A partial maintenance inspection in May 2009 using a 5kV Meggar indicated good insulation test readings. No testing was indicated of Section 1 (A-toward generator and B-toward main transformer). | 4 | 200000 (30) | (10) | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6723 | 6726 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 286 | 6 | See details below. | 3a | (30) | 10 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6726 | 7181 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-1 | N/A | 287 | 6 | Unit Board UB1 Protection 2005 are satisfactory. Relays and cases required cleaning due to ingress of dust and foreign material. | 3a | (25) | 10 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | N/A | 288 | 6 | PM performed between 1992 and 1997. Externally refurbished, and the protection relay changed on some breakers. All 600V switchgear is applied within their ratings. | 3a | (30) | 10 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6726 | 7183 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC A1 | N/A | 289 | 6 | Aging. Selective refurbishment required over time to maintain service. | 10 | (25) | 5 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6728 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 290 | 6 | Last equipment check 04 Feb 2010. 129VDC Battery Charger 2 (1969) to be replaced in 2010. | 3a | (20) | 20 | 2041 | | 2010 | Yes | No | 2010 |
| 1296 | 6690 | 6723 | 6728 | 99043229 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 291 | 6 | Installed 1998. Replacement date 2023. Last equipment maintenance check was 04 Feb. 2010. | 3a | (25) | 15 | 2041 | 2011 | | Yes | No | 1998 |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | N/A | 292 | 6 | End of Life. Plan to replace in 2010. | 3a | (25) | 10 | 2041 | | 2010 | Yes | Yes | 2010 |
| 1296 | 6690 | 6723 | 7184 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | N/A | 295 | 6 | MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers. | 3a | (25) | 3 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 7186 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | N/A | 296 | 6 | MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers. | 3a | (25) | 3 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | N/A | 297 | 6 | Batteries changed at 7 years and tested every 4 weeks. Maintenance performed 04 Feb. 2010. | 3a | (25) | 10 | 2041 | | | No | No | 1997 |
| 1296 | 6690 | 6723 | 270296 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 298 | 6 | Normal inspections and PM every 10 years have not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power and control, are "thrown" into trays that have been convenient in the routings associated with the new installations. | 4 | (50) | (30) | 2041 | | | Yes | No | 1970 |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | N/A | 299 | 6 | No recent testing. | 4 | (50) | (10) | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | N/A | 300 | 6 | No recent testing. | 4 | (50) | (10) | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 309894 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V METRIC PLUGS | 600 V METRIC PLUGS | N/A | 301 | 6 | New. | 3a | (30) | 30 | 2041 | | | Yes | Yes | 2009 |

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.1.3.5 Actions – Unit 1 Electrical and Control Systems

Where a system is fully or partially required for synchronous condensing, it is included here. The following actions are recommended for the Unit 1 electrical and control systems:

**TABLE 8-16 ACTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 6721 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 191 | 6 | Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6721 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 192 | 6 | Test Station Service Transformers UT1 and UT2 Protection Panels - next tests planned for 2012, 2018, 2024, etc. | 2012 | 1 |
| 1296 | 6690 | 6723 | 6721 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 193 | 6 | Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015, to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6722 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 194 | 6 | Assess migrating Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2011 | 1 |
| 1296 | 6690 | 6723 | 291668 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 195 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6724 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | N/A | 196 | 6 | Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows:<br>Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6726 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 197 | 6 | See details below. | | |
| 1296 | 6690 | 6723 | 6726 | 7181 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-1 | N/A | 198 | 6 | No action recommended. | | |
| 1296 | 6690 | 6723 | 6726 | 7182 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Power Centre "A" UAB1, (600V) | 199 | 6 | Change all Power Centre "A" UAB1, (600V) protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker A1, secondary of transformer AT-A<br>- Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Power Centre "A" UAB1, (600V) | 200 | 6 | Inspect and test transformer AT-A and the individual AK-50 / AK-25 air circuit breakers, and the bussing checked - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and re-torqued. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Power Centre "A" UAB1, (600V) | 201 | 6 | Overhaul to an "as new condition" or replace the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2012 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7183 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC A1 | | 202 | 6 | Not reviewed. | | |
| 1296 | 6690 | 6723 | 6728 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | Battery Chargers | 203 | 6 | Continue Planned Maintenance on newer units | 2011 | 2 |
| 1296 | 6690 | 6723 | 6728 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | Battery Chargers | 204 | 6 | Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010. | 2010 | 1 |
| 1296 | 6690 | 6723 | 6728 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | Battery Chargers | 205 | 6 | Replace Unit 1, 258VDC Panel and breakers installed in 1969 | 2010 | 1 |

Table 8-16 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 6728 | 99043229 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 206 | 6 | No action recommended. | | |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | N/A | 207 | 6 | No action recommended. | | |
| 1296 | 6690 | 6723 | 7184 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | MCC's, C2, C3, C4 | 208 | 6 | Conduct a study of how the distribution system (4160V, 600V, MCC's, cabling, etc.) is impacted by changes between 2010 and 2020, and before the start of the suggested Condition Evaluation Report addressed in other sections. | 2011 | 1 |
| 1296 | 6690 | 6723 | 7186 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | MCC's, C2, C3, C4 | 211 | 6 | Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC (Reference the Stantec Report – Holyrood Generating Station MCC Assessment, dated January 15, 2009). | 2011 | 1 |
| 1296 | 6690 | 6723 | 7193 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | UPS1 Inverter | 212 | 6 | Overhaul/upgrade unit to extend the life expectancy to at least 2020. | 2012 | 2 |
| 1296 | 6690 | 6723 | 7193 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | UPS1 Inverter | 213 | 6 | Optimize in conjunction with UPS2, UPS3 and UPS4 the possible replacement of the four units with two parallel units for requirement for inverters from 2020 to 2041. | 2012 | 2 |
| 1296 | 6690 | 6723 | 7193 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | UPS1 Inverter | 214 | 6 | Maintain PM program for the 120/208V, 3ph Distribution Panel-boards panels and breakers fed from UPS1 inverter, via Distribution Splitter. | 2011 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Switchgear, 4160V/600V | 215 | 6 | Assess Switchgear, 4160V/600V relaying in UB1modernization study for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270295 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 216 | 6 | Overhaul all 4160V switchgear breakers. Consider with the availability of spare breaker elements a program to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2011 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 217 | 6 | Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consider the Eaton Electrical Remote racking device (RPR2) to allow remote racking of breaker from up to 50ft away, and is programmable for other types of breakers. One RPR2 would service U1 and U2 needs. | 2012 | 1 |
| 1296 | 6690 | 6723 | 270296 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 218 | 6 | Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out. | 2011 | 3 |
| 1296 | 6690 | 6723 | 270297 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | N/A | 219 | 6 | Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. | 2011 | 3 |
| 1296 | 6690 | 6723 | 270298 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | N/A | 220 | 6 | Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable. | 2011 | 3 |
| 1296 | 6690 | 6723 | 309894 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V MELTRIC PLUGS | 600 V MELTRIC PLUGS | N/A | 221 | 6 | No recommended action. Complete install. | | |

### 8.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. Table 8-17 below illustrates the risk assessment for the Unit 1 electrical and control systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-17 RISK ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6723 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 181 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | Relay Room Protection & Control | 182 | 6 | Electrical fault, mechanical fault, ops error. | 10 | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Switchgear, 4160V/600V | 183 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | Main Controls | 184 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss of unit. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | DCS | 185 | 6 | Electrical fault, ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit | Maintain. |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | Generator Bus-Duct and Connections | 186 | 6 | Electrical fault. | (10) | None | 3 | C-D | Medium/ High | 3 | C-D | High | Loss 1 unit generation, damage to unit Safety | Current inspection and maintain. |
| 1296 | 6690 | 6723 | 6726 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | | 187 | | See details below. | 10 | None | | | | | | | | |
| 1296 | 6690 | 6723 | 6726 | 7181 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-1 | | 188 | | Electrical fault, mechanical fatigue, ops error. | 10 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Power Centre (600V) | 189 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6726 | 7183 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC A1 | N/A | 190 | | Mech/elect failure. | 5 | None | 3 | B | Medium | 3 | A | Low | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6728 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | Battery Chargers | 191 | 6 | Electrical or chemical fault. | 20 | None | 1 | B | Low | 1 | B | Low | Unit damage on fail to safe shutdown | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6728 | 99043229 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 192 | | Electric failure. | 15 | None | 1 | B | Low | 1 | B | Low | Unit damage on fail to safe shutdown | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | N/A | 193 | | Electric failure. | 10 | None | 1 | B | Low | 1 | B | Low | Unit damage on fail to safe shutdown | Refurbish or replace. |
| 1296 | 6690 | 6723 | 7184 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | MCC's, C2, C3, C4 | 194 | 6 | Electrical fault, mechanical fatigue, ops error. | 3 | None | 3 | C | Medium | 3 | C | High | Loss 1 unit generation, damage to equipment | Refurbish or replace. |
| 1296 | 6690 | 6723 | 7186 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | MCC's, C2, C3, C4 | 195 | 6 | Electrical fault, mechanical fatigue, ops error. | 3 | None | 3 | C | Medium | 3 | C | High | Loss 1 unit generation, damage to equipment | Refurbish or replace. |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | UPS Inverter 1,2,3,4 | 196 | 6 | Electrical fault. | 10 | None | 3,1 | B | Medium, Low | 1 | B | Low | Unit damage on fail to safe shutdown | Refurbish or replace. |
| 1296 | 6690 | 6723 | 270296 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 197 | | Electrical fault. | (30) | None | 1 | C | Low | 1 | B | Low | Loss up to 1 unit generation. Damage to equipment. | Clean and re-organize. |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | Cables | 198 | 6 | Electrical fault. | (10) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage | Test indicative number. |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | Cables | 199 | 6 | Electrical fault. | (10) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage | Test indicative number. |
| 1296 | 6690 | 6723 | 309894 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V MELTRIC PLUGS | 600 V MELTRIC PLUGS | N/A | 200 | | Not addressed in detail. | 30 | None | 1 | C | Low | 1 | C | Low | | |

### 8.1.3.7 Life Cycle Curve and Remaining Life

Figures 8-6 and 8-7 below, illustrate the life cycle curves for the Unit 1 electrical and control systems associated with generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

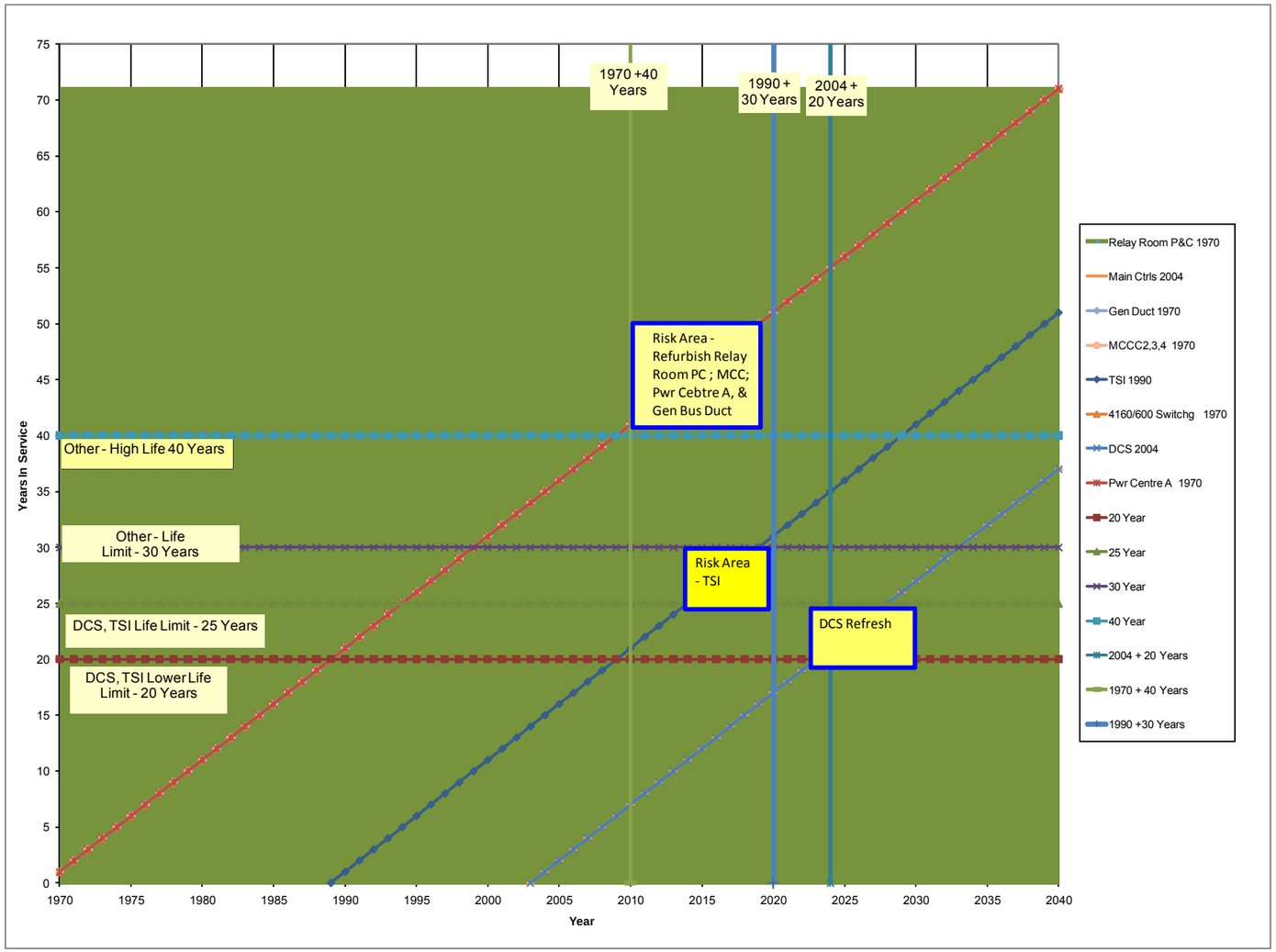



**FIGURE 8-6 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)**

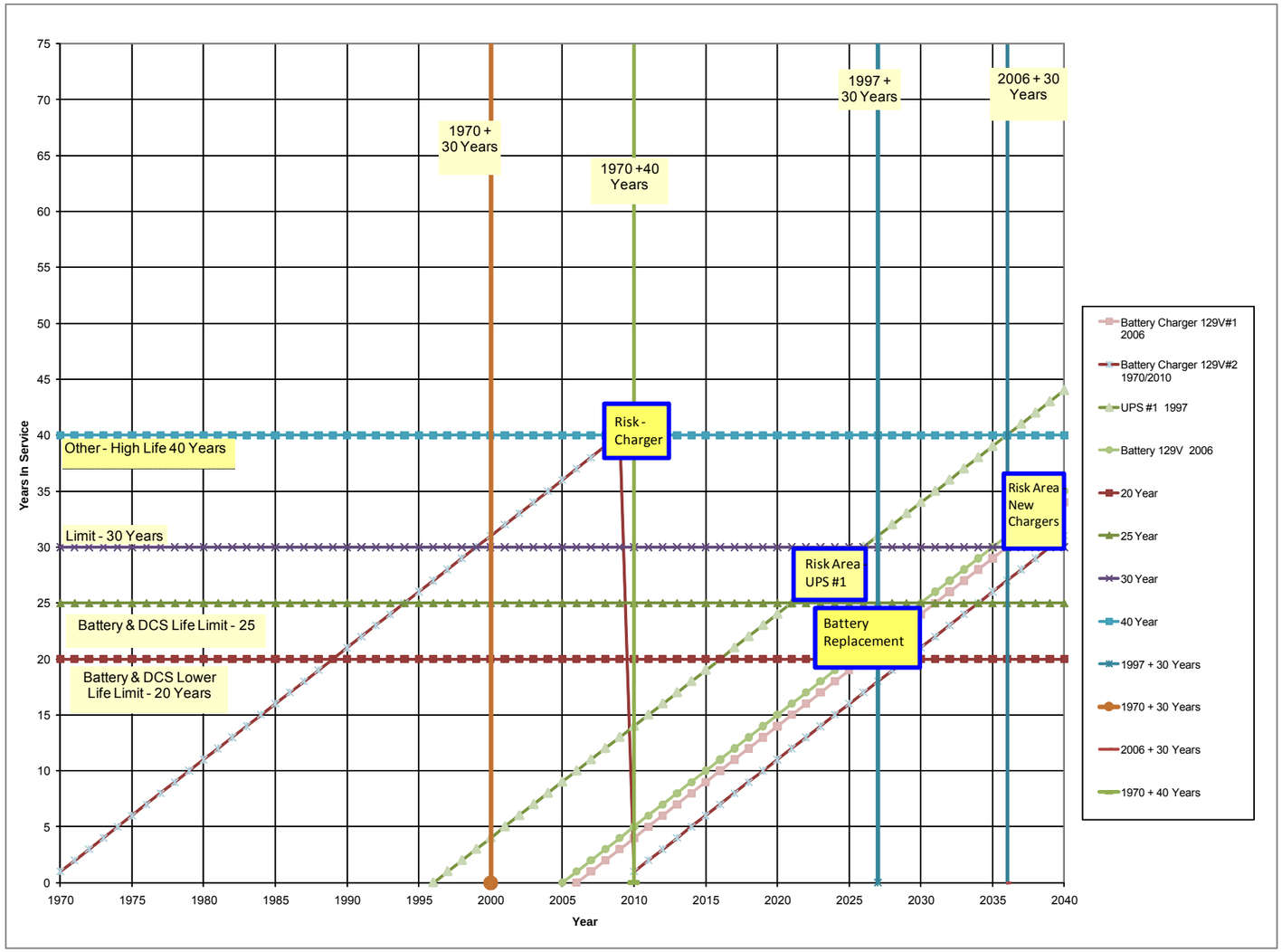



**FIGURE 8-7 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)**

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that most of the rest of the equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

### 8.1.3.8 Level 2 Inspections – Unit 1 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the Table 8-18.

**TABLE 8-18 LEVEL 2 INSPECTIONS– UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | None | 169 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | None | 170 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | None | 171 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | None | 172 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | None | 173 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | Generator Bus-Duct and Connections | 174 | 6 | Conduct in 2011 a complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct:<br>Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct. | 2011 | 1 | $15 |
| 1296 | 6690 | 6723 | 6726 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | None | 175 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6726 | 7181 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-1 | None | 176 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Power Centre "A" UAB1, (600 | 177 | 6 | Inspection and testing of transformer AT-A and the individual AK-50 / AK-25 air circuit breakers, and the bussing checked. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and re-torqued. Inspection and testing of the transformer should include turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. | 2011 | 2 | $6 |
| 1296 | 6690 | 6723 | 6726 | 7183 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC A1 | None | 178 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6728 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | None | 179 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6728 | 99043229 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | None | 180 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | None | 181 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 7184 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | None | 182 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 7186 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | None | 183 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER | UPS INVERTER | None | 184 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 270296 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 185 | 6 | No Level 2 required. | | 2 | |

Table 8-18 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 186 | 6 | Inspection and test selected control cables (especially if the cables are required to be re-run to different equipment):<br>- Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. | 2011 | 2 | $7 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 187 | 6 | Inspection and test selected power (4160V, 600V) cables (especially if the cables are required to be re-run to different equipment):<br>- Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. Check the resistance values are below the manufacturer's recommended maximum value.<br>- Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable. | 2011 | 2 | $10 |
| 1296 | 6690 | 6723 | 309894 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V METRIC PLUGS | 600 V METRIC PLUGS | None | 188 | 6 | No Level 2 required. | | | |

### 8.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

**TABLE 8-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 136 | | No capital required. | | |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | N/A | 137 | 6 | Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 138 | 6 | Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2014 | 2 |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | N/A | 139 | 6 | None planned, but may result from inspection and tests. | | |
| 1296 | 6690 | 6723 | 6726 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 140 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 6726 | 7181 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-1 | N/A | 141 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | N/A | 142 | 6 | Change all protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker A1, secondary of transformer AT-A.<br>- Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | N/A | 143 | 6 | Conduct a complete overhaul to an “as new condition” or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2012 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7183 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC A1 | N/A | 144 | | No capital required. | | |
| 1296 | 6690 | 6723 | 6728 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 145 | | No capital required. | | |
| 1296 | 6690 | 6723 | 6728 | 99043229 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 146 | 6 | Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010. | 2010 | 2 |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | N/A | 147 | 6 | Replace Unit 1, 258VDC Panel and breakers. | 2010 | 2 |
| 1296 | 6690 | 6723 | 7184 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | N/A | 150 | 6 | Address issues of MCC’s C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC. | 2012 | 1 |
| 1296 | 6690 | 6723 | 7186 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | N/A | 151 | 6 | Address issues of MCC’s C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC. | 2012 | 1 |

Table 8-19 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER #1 | UPS INVERTER | N/A | 152 | 6 | Overhaul/upgrade unit to extend the life expectancy to at least 2020. | 2012 | 1 |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER #1 | UPS INVERTER | N/A | 153 | 6 | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 154 | 6 | Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 155 | 6 | Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 156 | 6 | Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) can be for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs. | 2012 | 1 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 157 | 6 | Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 158 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 270296 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 159 | 6 | Install new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | N/A | 160 | 6 | Install new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | N/A | 161 | 6 | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM | DCS | N/A | 162 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 309894 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V METRIC PLUGS | 600 V METRIC PLUGS | N/A | 163 | 6 | Complete the NLH program of 600V, 3ph, plugs and receptacles on the four Pump feeders left to modify, two on Unit 1 and two on Unit 2 to the LP Drains Pumps. | 2010 | 3 |

### 8.1.4 Asset 280182 - Unit 1 Cooling Water Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendices 8 and 11)

The requirements for the cooling water systems associated with generators for Holyrood are as follows:

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8715 #1 Unit Generation Services |
| Sub-Systems: | 270182 #1 CW System |
| Components: | 7137 #1 CW Travelling Screens East |
| | 7138 #1 CW Travelling Screens West |
| | 7146 #1 CW Pump East |
| | 7147 #1 CW Pump West |
| | 7134 #1 CW Intake |
| | 7138 #1 CW Discharge to Outfall |
| | 6719 #1 General Service Water |
| | 6782 #1 Turbine Generator Cooling Water |

#### 8.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouse sea water intake, traveling screens, and general service water system;
- Sea water heat exchanger system;
- Seawater discharge system; and
- Electrical and control requirements.

**Circulating Water (CW) Pump & Screen Systems:** Circulating water (CW) systems servicing Unit 1 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

**Turbine Generator (TG) Auxiliary Cooling Water System:** Sea water cooling is required for the TG Auxiliary Cooling Water system required for synchronous condensing operation. For Unit 3, it can currently be supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump

pit), from the water take-off from the Stage 2 pumphouse cooling water pumps, and from an interconnection with the Units 1 and 2 cooling water system. Typically when only Unit 3 is running as synchronous condenser, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For the purpose of long term synchronous generation operation to 2041 of all three units, the intent is to supply seawater from a small, permanent pump arrangement similar to Unit 3. It may come from the one pumphouse or in the form of two separate, but interconnected systems.






**FIGURE 8-8 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING TG AUXILIARY COOLING WATER**

### 8.1.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Overhaul/Inspection | Not identified |
| Next Major Overhaul/Inspection | Not Identified |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 166 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 210 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 219 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 219 | 120 |
| Starts Actual - Ops to Dec 2009 | 482 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 714 | 130 |

#### 8.1.4.3 Inspection and Repair History

**CW Travelling Screens:** Travelling screen internals have been replaced on Unit 1 in the last 5 to 10 years. Interviews suggest that no recent issues have been experienced with these units. Visual examination confirms that generally the Unit 1 screens appear to be in good shape.

The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

**CW Wash Water Pumps and Motors:** An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**CW Pumps:** CW pumps are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 8-20 below.

**TABLE 8-20 MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. Further the system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

**CW Pump Motors:** The CW Pumps are driven by 4 kV motors. The motors are the original equipment and are tested electrically every year in accordance with the plant PM process. They are in good condition, but beyond their normal physical life expectation.

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves, and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the Unit 1 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

**Cooling Water System Intake & Discharge:** The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condenser has periodically been dewatered and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per schedule below in Table 8-21.

**TABLE 8-21 PM INSPECTIONS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 8.1.4.4 Condition Assessment

The condition assessment of the Unit 1 cooling water systems associated with generators is illustrated below in Table 8-22.

**TABLE 8-22 CONDITION ASSESSMENT – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 255 | 12 | PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected. | 4 | (50) | 30 | 2041 | 2011 | | Yes | Yes | 1990 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 256 | 11,15 | Piping, pumps, and heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available. | 4 | 200000 (30) | 10 | 2041 | 2011 | | Yes | No | 1970 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Sea Water Piping | 257 | 11,15 | Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid. | 3a | 200000 (30) | (10) | 2041 | 2011 | | Yes | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Intake structure and foreay | 269 | 11 | No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack. | 4 | (60) | (20) | 2041 | | 2011 | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Pit, Stoplogs and Discharge | 270 | 11 | No recent underwater inspections of pit, stoplogs or outfall structures. | 4 | (60) | (20) | 2041 | | 2011 | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7137 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS EAST | N/A | 271 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2011 | | No | No | 2000 |
| 1296 | 6690 | 6715 | 270182 | 7138 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS WEST | N/A | 272 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2011 | | No | No | 2000 |
| 1296 | 6690 | 6715 | 270182 | 8819 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | N/A | 273 | 11 | Significant corrosion. Likely near end of life. | 4 | (30) | 5 | 2041 | | | No | No | 1970 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 cooling water system associated with generators:

**TABLE 8-23 RECOMMENDED ACTIONS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | N/A | 162 | 12 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6719 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 163 | 12 | Continue current inspection and maintenance activities. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 164 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 165 | 8 | Clean and coat remaining Auxiliary Cooling water piping. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 166 | 8 | Perform representative Level II pipe thickness checks on seawater intake and discharge piping. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 167 | 8 | Perform Level 2 inspection on Aux Cooling Pipes during next five years. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 168 | 8 | See details below. | | |
| 1296 | 6690 | 6715 | 6782 | 9592 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP SOUTH | T/G COOLING PUMP SOUTH | N/A | 169 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 6782 | 9593 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP NORTH | T/G COOLING PUMP NORTH | N/A | 170 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 182 | 11 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Intake | 183 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplogs. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Outfall | 184 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplogs. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7137 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS EAST | N/A | 185 | 11 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7138 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS WEST | N/A | 186 | 11 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 8819 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | N/A | 187 | 11 | Refurbish pump/motor. | 2011 | 3 |

### 8.1.4.6 Risk Assessment

Table 8-24 below illustrates the risk assessment for the cooling water systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-24 RISK ASSESSMENT – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6715 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | N/A | 156 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Pump/Motor Failure | 157 | 12 | Mechanical or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Minimum | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Ht Exch Failure | 158 | 12 | Mechanical failure/pluggage. | 10 | None | 1 | A | Low | 1 | A | Low | Seawater contamination (unlikely) | Inspect and maintain. |
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Piping Failure | 159 | 12 | Mechanical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact | Inspect and maintain. |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Units 1&2 ACW Piping | 160 | 8 | Corrosion, mechanical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact | Inspect and maintain. |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Units 1 & 2 Seawater Piping | 161 | 8 | Corrosion, mechanical failure. | (10) | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact | Inspect and maintain. |
| 1296 | 6690 | 6715 | 6782 | 9592 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP SOUTH | T/G COOLING PUMP SOUTH | Units 1&2 ACW Pump/Motor | 162 | 8 | Mechanical or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Sparing, minimal | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 6782 | 9593 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP NORTH | T/G COOLING PUMP NORTH | Units 1&2 ACW Pump/Motor | 163 | 8 | Mechanical or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Sparing, minimal | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Unit #1 CW Outfall Piping | 175 | 11 | Concrete cracking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair | Inspect and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7137 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS EAST | Travelling Screens | 176 | 11 | Corrosion- Internal/Ext. | (10) | None | 2 | B | Low | 2 | A | Low | Condenser plugging | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7138 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS WEST | Travelling Screens | 177 | 11 | Corrosion- Internal/Ext. | (10) | None | 2 | B | Low | 2 | A | Low | Condenser plugging | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 8819 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | Pumps\ & Motors | 178 | 11 | Corrosion- Internal/Ext. | (5) | None | 3 | A | Low | 2 | A | Low | Major leak and repair/patch | Inspect and maintain. |

### 8.1.4.7 Life Cycle Curve and Remaining Life

Figure 8-9 below, illustrates the life cycle curves for the major elements of the Unit 1 cooling water systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them at this time, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

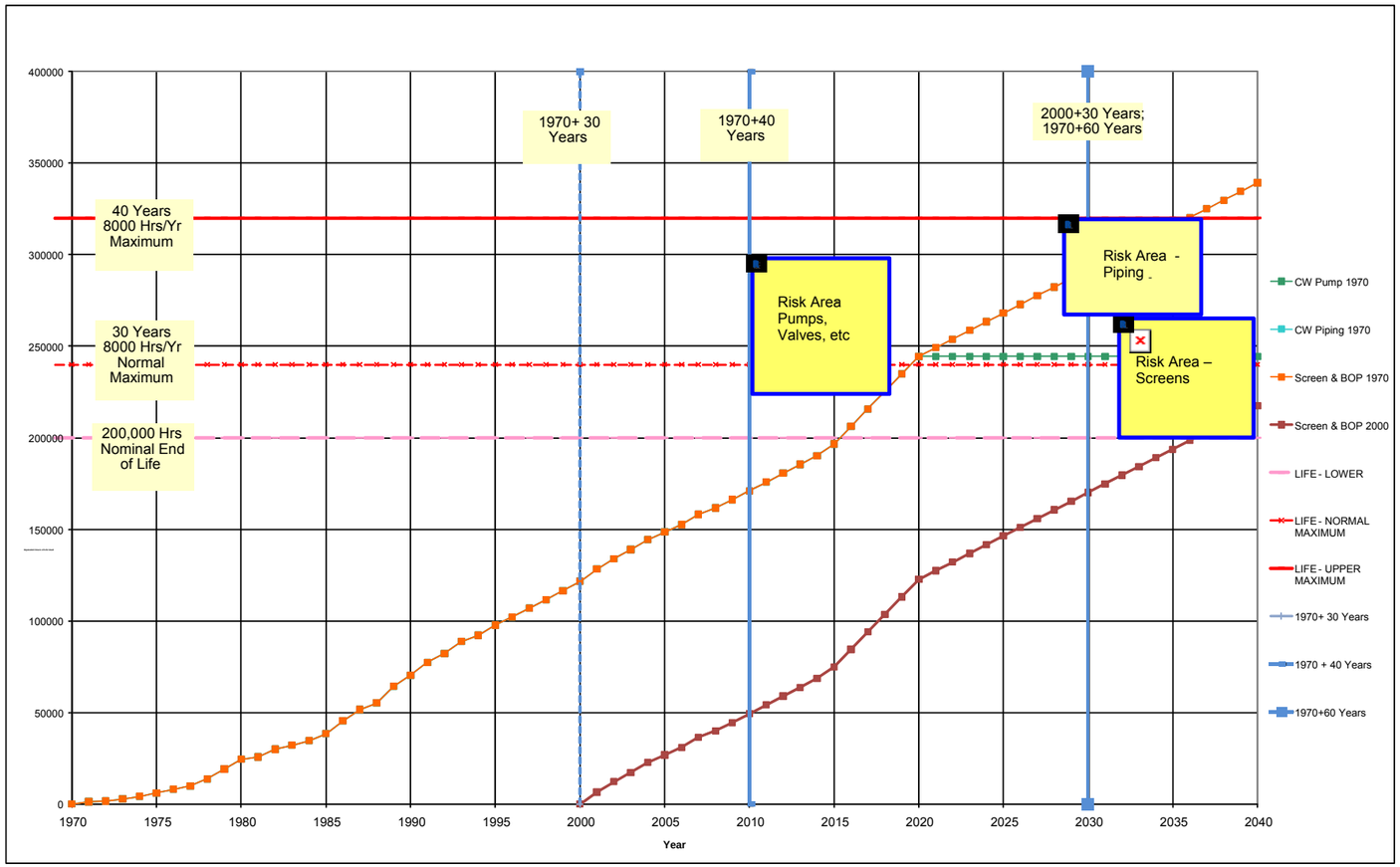



**FIGURE 8-9 LIFE CYCLE CURVE – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

The curve indicates that the remaining life (RL) of most elements of the Unit 1 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not necessarily the 2041 end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. Curves for the intake and outfall structures and associated sub-components should be added subsequent to the undertaking of a Level 2 inspection.

### 8.1.4.8 Level 2 Inspections – Unit 1 Cooling Water Systems Associated with Generators

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-25 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-25 LEVEL 2 INSPECTIONS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | None | 147 | N/A | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | None | 148 | 12 | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Seawater intake and discharge piping | 149 | 8 | Perform representative Level 2 pipe thickness checks. | 2011 | 2 | $6 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | AC Water piping | 150 | 8 | Thickness spot checks within 5 years. | 2011 | 2 | $6 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | None | 151 | 8 | AC Water Ht Exchangers shell and tubes within 5 years. | 2011 | 2 | $6 |
| 1296 | 6690 | 6715 | 6782 | 9592 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP SOUTH | T/G COOLING PUMP SOUTH | None | 152 | 8 | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 6782 | 9593 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP NORTH | T/G COOLING PUMP NORTH | None | 153 | 8 | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | CW intake and discharge structures and piping | 162 | 11 | Inspections – diver visual inspection within 2 to 4 years. | 2011 | 2 | $30 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | CW intake and discharge structures and piping | 163 | 11 | Inspections – diver visual inspection within 2 to 4 years. | 2011 | 2 | $30 |
| 1296 | 6690 | 6715 | 270182 | 7137 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS EAST | None | 164 | 11 | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 270182 | 7138 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS WEST | None | 165 | 11 | No Level 2 required. | | | |
| 1296 | 6690 | 6715 | 270182 | 8819 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | None | 166 | 11 | No Level 2 required. | | | |

### 8.1.4.9 Capital Projects

Table 8-26 below shows the suggested typical capital enhancements that should be considered for the Unit 1 cooling water systems associated with generators:

**TABLE 8-26 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 6719 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 115 | 12 | No capital required. | | |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 116 | 8 | Clean and coat AC Water pipes. | 2012 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 117 | 8 | No capital required. | | |
| 1296 | 6690 | 6715 | 6782 | 9592 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP SOUTH | T/G COOLING PUMP SOUTH | N/A | 118 | 8 | No capital required. | | |
| 1296 | 6690 | 6715 | 6782 | 9593 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP NORTH | T/G COOLING PUMP NORTH | N/A | 119 | 8 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Intake structure and foreay | 129 | 11 | Add system for synchronous condensing similar to Unit 3. | 2014 | 1 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Pit, Stoplogs and Discharge | 130 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7137 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS EAST | N/A | 131 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7138 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W.TRAVELLING SCREENS WEST | N/A | 132 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 8819 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | N/A | 133 | 11 | No capital required. | | |

## 8.2 Unit 1 – Lower Priority Systems

### 8.2.1 Asset 6699 Unit 1 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30 and 34)

The equipment associated with the Unit 1 boiler system is listed below:

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6899 #1 Boiler Plant |
| Sub-Systems: | 6700 #1 Boiler Structure |
| | 6701 #1 Boiler F.W. & Sat. Steam |
| | 6702 #1 Boiler Superheater and Reheater |
| Components: | 6869 #1 Economizer, tubing and headers |
| | 6871 #1 Linking piping (boiler internal) |
| | 6871 #1 Furnace water circuit<br>6870 #1 Steam drum,<br>6871 #1 Downcomers and feeder piping<br>6871 #1 Lower Waterwall headers<br>6871 #1 Waterwall tubing<br>6871 #1 Upper Waterwall headers, and riser piping |
| | 6873/6878 #1Superheater,headers and tubing |
| | 6878 #1 Reheater, headers and tubing |
| | 6871 #1 Safety Valves |
| | 6876 #1 Boiler Main Steam lines |
| | 6902 #1 Boiler Stop Valve |
| | 6700 #1 Furnace structural, hangers and casing |
| | 6706 #1 Boiler Blowdown Tank |

#### 8.2.1.1 Description

Unit 1 boiler is a Combustion Engineering (now supported by ALSTOM), natural circulation, single reheat, pressurized unit. The boiler was originally designed in 1968 for an output of 150 MW with a maximum steam flow of 127 kg/s (1,050,000 lbs/hr), at 12.41 MPag (1800 psig) and 538 °C (1000 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 116 kg/s (921,000 lbs/hr) with an inlet temperature of 365 °C (690 °F) and an outlet temperature of 541 °C (1005 °F). HTGS Stage I (Units 1 & 2) was commissioned in 1969/1970.

Unit 1 was uprated to nominal output of 175 MW in 1988/1889. The boiler was analyzed to determine if this increased load could be accommodated by raising the superheat steam flow approximately 11% to 141 kg/s (1,167,200 lb/hr) and the reheat steam flow approximately 13% to 126 kg/s (1,044,630 lb/hr). Associated boiler pressure part modifications were evaluated such that the boiler design pressure of 15.2 MPa (2205 psig) could be maintained with the increased steam outlet pressure. All the pressure parts were analyzed for ASME Code compliance and optimized operation. In order to reduce anticipated attemperator spray water in the superheater section, heating surface was removed from the primary superheater sections. Additional modifications were made to the boiler non-pressure part equipment. After uprating, the boiler is rated at a maximum steam flow of 141 kg/s (1,167,000 lbs/hr), at 13.58 MPag (1970 psig) and 541 °C (1005 °F) with an inlet feedwater temperature of 240 °C (464 °F)353 °C (667 °F) and an outlet temperature of 541 °C (1005 °F).

The system includes:

- Economizer, tubing and headers;
- Linking piping (boiler internal);
- Furnace water circuit;
    - Steam drum,
    - Downcomers and feeder piping as required
    - Lower Waterwall headers
    - Waterwall tubing
    - Upper Waterwall headers, and riser piping as required
- Superheater; headers and tubing;
- Reheater; headers and tubing;
- Safety valves;
- Furnace combustion systems; burners, fans, air heaters;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

Boiler #1 had superheater sections replaced in 2007. Boiler sootblowers were added in 1995. Unit 1 was upgraded in 1988 to 175 MW from 150 MW.

#### 8.2.1.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Major Inspection/Maintenance Repair | Annual May to Sep on all units |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |
| | |
| Max Hours Ops – 1986 to Dec 2009 | 121 |
| Max Hrs - 1986 to Dec 2015 | 165 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 174 |
| | |
| Max Hours Ops – 2007/8 to Dec 2009 | 8 |
| Max Hrs – 2007/8 to Dec 2015 | 54 |
| Max Hrs – 2007/8 to Gen End Date Dec 2020 | 174 |

#### 8.2.1.3 Inspection and Repair History

**Asset 6869 Economizer**

As per part of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers (inspection results were not available). The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 1.

During the 2002 outage, a thermocouple was installed on the economizer inlet header near the inlet pipe. Also, the economizer inlet and outlet headers were opened for debris removal and internal inspection. Loose debris was found in the inlet header and was removed.

There was a failure in the economizer inlet header stub tube in November 2003. A small circumferential crack was observed on the top side of the horizontal element at a location less than 2.5 cm (1 inch) from the economizer inlet header, in the bottom row of economizer assembly #1 (counting left to right). When the tube sample was split longitudinally, deep circumferential cracking was observed on both the top and bottom sides of the horizontal element at the leak site. The destructive examination of the sample established that the section of economizer nipple tubing had suffered extensive internal damage and that this internal damage was the direct cause of the leak. It was concluded that the damage was due to combination of thermal fatigue and corrosion-fatigue cracking related mechanisms. The fact that the cracking was concentrated on the top and bottom sides of the tube in the failure area may indicate the influence of a bending load during service. It was further noted that the internal damage had been substantially augmented by significant external wastage due to low temperature corrosion related to condensation. The failed tube section was removed and replaced with available tube material.

During the 2004 outage, an inspection of the selected tube stubs at both ends and middle of the inlet header (visual and angle beam UT) found no indication of damage similar to the failure that occurred in the fall of 2003 discussed above. The inlet header supports were exposed and found to be in good condition. However, the sootblower pipe supports were removed from the header to eliminate any external loads.

**Asset 6871 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes**

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after boiler repairs. Apart from the repair debris, pipe stubs were also found in the header. The stubs were about 23 cm (9.5 inch) long by 6.3 cm (2.5 inch) outside diameter (OD) and were threaded at one end. It is believed that these pipe stubs were used for the initial fit-up and welding of the sidewalls. There were no internal inspections to check for ligament cracking or cracking at other locations.

UT measurements were taken on the waterwall circuit feeder and riser tubes and some of the riser tubes were found in contact with each other but no damage was noted.

**Asset 6870 Steam Drum**

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although slight pitting was observed but not active, it is not considered a pressure integrity issue for the steam drum.

**Asset 6871 High Temperature Headers and Piping**

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on selective tube to header welds on the superheater and reheater section headers subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

The superheater five (SH5) and superheater six (SH6) headers were opened and cleaned as part of the superheater work during the 2008 maintenance outage. Significant cracking was found in the handhole bore on the SH6 header located on the east side. These cracks were removed and repaired. There has been no internal inspection carried out for ligament cracking on any of the headers in the superheater section.

A visual inspection of the header supports is performed during every maintenance outage. During the 2008 outage, it was observed that all hangers appeared to be bearing load except for 2, 3 and 4 from the east and 2 and 3 from the west under SH3 and number 2 from each side under SH4. These hangers should normally support the casing floor under the headers.

During every maintenance outage, MPI on the selective tube to header welds is carried out on all the reheat section headers (RH1 and RH2) subject to accessibility. There has been no abnormality observed to date. Also, UT measurements are taken on the headers next to MPI location. No significant header wall thinning was observed.

A visual inspection of the superheater link piping is carried out during outage inspections.

**Asset 6873 Superheater Link Piping and Attemperator**

A visual inspection of the superheater link piping is carried out during every outage. There was no internal inspection carried out on superheater attemperators during the 2001-2009 period.

**Asset 6869 Economizer Tubes**

In November 2003, there was a failure in the economizer inlet header stub tube. It was documented during 2005 outage inspection that the third tube from the west side previously failed and was removed from service and plugged at the headers. The cause of this failure is unknown. This was the same location of a tube failure on Unit 2 in April 2005 due to corrosion fatigue at a mill defect in the tube. The Unit 2 tube alignment was reported to have been in good condition.

During 2009 outage, some of the baffle plates were found to be dislocated. This was repaired and the plates secured. As per part of routine NDE inspection, UT measurements are taken at specified locations on the economizer tube bends.

**Asset 6871 Waterwall Tubes**

During 2007 outage, a boiler chemical cleaning was performed. The tube damage apparent after the cleaning of the waterwalls for the 2006 thickness survey was repaired. Two viewports were rebuilt due to their deteriorating condition. A thermocouple was installed on each side waterwall as requested by the Department of Government Services. A LFET was completed on the waterwall tubes in 2007 and the tubes in the high heat zone of the furnace were found to be in good shape.

During the 2008 outage, an internal boroscope inspection was completed on six front wall tubes and ten baffle wall tubes over the full length of each tube. No significant problems were observed. Extensive pitting was observed around many of the burners and significant corrosion was noted in the lower furnace on the south side as observed during previous outages. Two observation ports were selected for replacement based on inspections of the refractory completed during the previous year. The sealboxes were found in good condition. It is not mentioned in the 2008 outage report whether a furnace floor tubes thickness survey was completed. (NOTE: A LFET was completed on the water wall tubes in 2007 and the tubes in the high heat zone of the furnace were found to be in good shape.)

**Asset 6873/6878 Superheater and Reheater Tubes**

The anti-vibration baffles were noted to be in very poor condition. There are minor tube alignment issues as some tubes had drifted laterally. However, the alignment did not appear to be worsening at that time. No significant tube thickness loss was discovered during the UT inspections performed at selective locations on the Unit 1 superheater and reheater sections during the 2008 outage. The tubes were well above the minimum wall thickness required. No tube sample analysis has been performed on the lower secondary superheater section on Unit 1. Also, recent tube thickness data is not available for the lower section.

During the 2005 outage, a tube spread and thickness survey was completed in the secondary superheater section to document tube thinning and alignment. The results indicated extensive thinning in the upper stainless steel section between the 7th and 8th floor cavities where the metal temperatures are the highest and the conditions most conducive for liquid ash corrosion.

A partial replacement of the Unit 1 secondary superheater was completed during the 2008 annual maintenance outage. Thirty one upper superheater assemblies (SA-213-EP-321H) were replaced because of severe thinning caused by OD corrosion and forced outages as a result of six tube failures from 2005 to 2008. The new assemblies were fabricated from 347H stainless steel tubes. This was an upgrade from the original 321H tubes. The assemblies were supplied with T22 (2-¼ chrome) safe-ends for welding to the T22 tube ends in the boiler and vestibule. Hence, the old DMWs (Dissimilar Metal Welds) were removed and replaced with new DMWs that were completed in the shop. In addition, one lower superheater assembly was replaced as well, which had been removed from service (plugged) during a forced outage repair completed in February of 2008.

**Asset 6878 Reheater**

There is a history of failure of spacer bars due to long term exposure to high temperatures causing a slight misalignment of the reheater tubes. The problem areas identified have been repaired and 309 grade stainless steel material has been used for all new spacers. Additional problem areas are likely to be identified during inspections. Although hanger tubes have bowed and touch each other at certain locations since 2001, the alignment of the reheater is not adversely affected. During the 2005 outage, extensive thinning in the bottom loop (stainless steel section) was noted.

During the 2008 outage, physical damage was discovered directly above the 7$^{th}$ superheater assembly from the east side due to previous catastrophic failures of that assembly. Thickness measurements were taken in the remaining reheater section. The results indicated little or no change since 2005 and no further tube failures have been observed in the reheater section.

**Asset 6871/6700 Safety Valves, Casings, & Structure/Hangers**

Safety relief valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the 2020 desired life.

Casing: The casing has a history of failures of both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel structure and hangers - corrosion in the boiler penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

**Asset 6706/7014 Boiler Blow Down Tank**

The unit is inspected annually, except in 2009 and 2010. In 2009, the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

### 8.2.1.4 Condition Assessment

The condition assessment of the Unit 1 boiler system is illustrated below in Table 8-27.

**TABLE 8-27 CONDITION ASSESSMENT – UNIT 1 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 52 | 30 | No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem for main steam, hot reheat and cold reheat lines. | 4 | 200000 (30) | (10+) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 53 | 30 | No information on recent inspections of the sample of the upper waterwall headers flat end welds. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 54 | 30 | High heat flux and challenging chemistry are related to numerous damage mechanisms on interior and exterior surfaces of waterwall tubing. No information on recent destructive testing reports of waterwall tubes that were removed in 2006. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Headers & link Piping | 55 | 30 | Outlet headers or link piping to the steam drum in good condition. Thermal/corrosion fatigue related failure experienced in the inlet headers stub tubes. Only partial internal and stub tube inspections in 2004 outage. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Tubing | 56 | 30 | Insufficient inspections to assess condition Wall thickness review inconclusive -some 2009 readings decreased and some increased vs 2004. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 6870 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | N/A | 57 | 30 | No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected. | 4 | 200000 (30) | 10+ | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Tubes | 60 | 30 | No significant life limiting issue has been observed in the primary superheater section tubes. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6874 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER SUPERHEATER ATTEMP. | N/A | 61 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemporators. No internal inspections of the attemporaters and link piping done to confirm the absence of thermal fatigue damage. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6877 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER ATTEMPERATOR | N/A | 62 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemporators. No internal inspections of the attemporaters and link piping done to confirm the absence of thermal fatigue damage. | 4 | 200000 (30) | (5) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Piping | 63 | 30 | Previous metallographic examinations of hot reheat piping discovered partially degraded microstructure but no evidence of creep. No NDE or metallographic examination after 2002. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Headers & link Piping | 64 | 30 | Design creep life calculations for reheater outlet headers suggest concern. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Tubing | 65 | 30 | No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Headers & link Piping | 66 | 30 | Design creep life calculations for secondary superheater outlet headers suggest concern. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Tubes | 67 | 30 | Partial replacement with upgraded materials of the secondary superheater sections in 2008 - expected to operate without failure up to the desired life. Destructive tube sample analysis is required for the lower secondary superheater section not replaced. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6701 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | N/A | 68 | 30 | Thinning, corrosion. Sefety issues - isolation and access | 10 | 200000 (30) | (2) | 2020 | 2011 | 2011 | Yes | No | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | Piping | 69 | 30 | Previous metallographic examinations of main steam piping discovered partially degraded microstructure but no evidence of creep. No NDE or metallographic examination after 2002. | 4 | 200000 (30) | (10) | 2020 | | 2011 | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | N/A | 70 | 30 | No recent information review. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2011 | Yes | No | 1970 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 boiler system:

**TABLE 8-28 RECOMMENDED ACTIONS – UNIT 1 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 61 | 30 | See details below. | | |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 62 | 30 | Monitor pitting on the tubes adjacent to the burners. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 63 | 30 | Monitor pitting on the waterwall slope under the economizer. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 64 | 30 | Monitor wall thinning on the south side waterwall floor tubes. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 65 | 30 | Review the destructive testing 2006 report of waterwall tubes to evaluate the findings. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 66 | 30 | Inspect selective flat end welds of the upper waterwall headers. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 67 | 30 | Inspect the selective feeder and riser tubes for corrosion fatigue damage. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 68 | 30 | Perform preliminary internal inspection of the lower waterwall headers at the locations of the degradation mechanisms identified for the steam drum, using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 69 | 30 | Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | N/A | 70 | 30 | Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the economizer tube in Unit 2 in 2005. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | N/A | 71 | 30 | Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | N/A | 72 | 30 | Perform Level 2 inspections of the economizer inlet header:<br>i. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed.<br>ii. UT inspection of stub tubes.<br>iii. Stub tube sample to assess evidence of FAC. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6869 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | N/A | 73 | 30 | Visually inspect the economizer outlet headers and supports and the economizer link piping during annual outages to ensure there is no change in the state and/or abnormal movement. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6870 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | N/A | 74 | 30 | Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6870 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | N/A | 75 | 30 | Perform external inspection of feeder tube welds. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6870 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | N/A | 76 | 30 | Manage steam drum target life with appropriate operational control and routine inspection and maintenance. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6871 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | FURNACE | N/A | 77 | 30 | See details below. | | |
| 1296 | 6690 | 6699 | 6702 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BLR SUPERHEAT& REHEAT ASS'Y | N/A | 78 | 30 | Inspect SH-5, SH-6 and RH-2 for creep and creep fatigue damage including internal boroscopic, for external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BLR SUPERHEAT& REHEAT ASS'Y | N/A | 79 | 30 | Investigate the condition that SH3 and SH4 hanger's not bearing load to identify cause and adverse affects. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6873 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | N/A | 80 | 30 | Inspect for the presence of inside pitting and scaling | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6873 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | N/A | 81 | 30 | Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues and failures of AVBs. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6874 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER SUPERHEATER ATTEMP. | N/A | 82 | 30 | Inspect attemperator and ID of the link piping for evidence of thermal fatigue. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6877 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER ATTEMP. | N/A | 83 | 30 | Inspect attemperator and ID of the link piping for evidence of thermal fatigue. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | N/A | 84 | 30 | Inspect to check the presence of inside pitting and scaling. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | N/A | 85 | 30 | Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues. | 2012 | 2 |

Table 8-28 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6702 | 6878 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | N/A | 86 | 30 | Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | N/A | 87 | 30 | Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues. . | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | N/A | 88 | 30 | As economically justified assess and implement the addition of reheater surface for reheat temperature and efficiency. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | N/A | 89 | 30 | Perform destructive tube sample analysis on the lower secondary superheater section that is not replaced so far, to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | N/A | 90 | 30 | Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | N/A | 91 | 30 | Refurbish and use the furnace exit thermoprobe during start-up activities. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6701 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | N/A | 92 | 30 | Replace tank | 2011 | 1 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | N/A | 93 | 30 | Implement an active high energy piping management program including NDE testing at key locations and an high temperature piping constant support hanger monitoring program. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | N/A | 94 | 30 | Inspect and refurbish/replace during next major boiler outage. | 2012 | 2 |

### 8.2.1.6 Risk Assessment

Table 8-29 below illustrates the risk assessment for the Unit 1 boiler system, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-29 RISK ASSESSMENT – UNIT 1 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Upper WW Headers | 58 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds. Corrosion. | 10 | Could meet the desired life with routine inspections. | 2 | B | Low | 2 | C | Medium | Flat end weld cracking. Wall thinning due to corrosion. | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Riser Tubes | 59 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 2 | C | Medium | Corrosion fatigue cracking - forced outage. | Inspections are required to assess remaining life. |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Lower WW Headers | 60 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking. corrosion. | (10) | No real life limiting issue. Additional inspections required. | 3 | B | Med | 3 | B | Medium | Ligament cracking and weld cracking. - forced outage. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Feeder Tubes | 61 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Corrosion fatigue cracking and wall thinning due to corrosion related mechanism - Forced outage for repair. | Inspections are required to assess remaining life. |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Downcomers | 62 | 30 | Thermal/mechanical fatigue cracking at the header support locations. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Thermal/Mechanical Fatigue Cracking at the header support locations - forced outage for repair. | Inspections are required to assess remaining life. |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Waterwall Tubes | 63 | 30 | Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion. | (10) | Some sections of floor tubes and pitting in some areas require attention, other than that no major life limiting issue observed. | 3 | B | Med | 3 | B | Medium | Tube wall thinning due to falling slag erosion on the floor tubes. Extensive pitting leading to tube failure. Tube leak/ forced outage for repair | Some sections of floor tubes and pitting in some areas require attention. |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Inlet Headers | 64 | 30 | Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC. | (10) | No real issue as per inspection to date. Additional inspections required | 3 | B | Med | 3 | B | Medium | Ligament cracking, tube stub thinning/cracking, weld cracking. Forced outage for repair. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 65 | 30 | Mechanical fatigue cracking, corrosion fatigue cracking, corrosion. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Weld cracking due to support failure - forced outage for repair. | Routine inspections. |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Tubes | 66 | 30 | External corrosion and corrosion fatigue. | (10) | Inspections are required to assess the remaining life | 1 | B | Low | 1 | B | Low | Tube failure due to corrosion, corrosion-fatigue. Tube leak/ forced outage for repair. | Inspections are required to assess remaining life. |
| 1296 | 6690 | 6699 | 6701 | 6870 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | Steam Drum | 67 | 30 | Thermal fatigue cracking, corrosion fatigue cracking. | (10) | No real issue as per inspection to date. Additional inspections required | 3 | C | Med | 3 | C | High | Ligament cracking. Weld cracking. Forced outage. Safety threat. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Steam Cooled Walls Outlet Header | 70 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Medium | Thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Inlet Header | 71 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Medium | Thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Outlet Header | 72 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | C | Low | 1 | D | Medium | Creep and thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Support Tube Inlet Header | 73 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | C | Med | 2 | D | High | Creep and thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required to assess the remaining life. |
| 1296 | 6690 | 6699 | 6702 | 6875 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Platen Inlet Header | 74 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | C | Low | 1 | D | Medium | Creep and thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6875 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Space Outlet Header | 75 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. Forced outage. Life Safety. | Additional inspections required to assess the remaining life. |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 76 | 30 | Fatigue, OD/ID corrosion, ID pitting. | 10 | No real life limiting issues; however, the presence inside pitting and scaling is not known. | 1 | C | Low | 1 | D | Medium | Tube failure due to excessive pitting and corrosion. Forced outage. Life Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6874 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER SUPERHEATER ATTEMP. | Superheater Link Piping and Attemperator | 79 | 30 | Thermal/mechanical fatigue, pitting corrosion. | (10) | No real issue as per external visual inspection to date. Additional inspections required | 3 | B | Med | 1 | D | Medium | Thermal/Mechanical Fatigue Cracking, Forced outage. Safety. | Additional inspections required. |
| 1296 | 6690 | 6699 | 6702 | 6877 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER ATTEMPERATOR | N/A | 80 | 33 | Not addressed in detail. | (10) | Additional inspections required to assess the remaining life. | 3 | B | Medium | 3 | C | High | Attemperator failure. Overtemperature of tubing and pipe failure | Inspection and refurbish or replace. |

Table 8-29 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Hot Reheat | 81 | 33 | Thermal/mechanical fatigue; creep, creep fatigue; corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1. No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found.. No major damages found during walkdowns. Walkdown summary part describes specific observations. | 3 | C | Med | 3 | D | High | Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations. Hanger/Support Inspection and monitoring. Program Level 2 assessments. |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Cold Reheat | 82 | 33 | Thermal/Mechanical Fatigue; Corrosion-Fatigue; Cracking; Corrosion | (10) | No seam-welded pipe. No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns. Walkdown summary part describes specific observations. | 1 | B | Low | 1 | D | Low | Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety. | Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level II assessments |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Inlet Header | 83 | 30 | Thermal fatigue. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Thermal fatigue cracking. Forced outage. Life Safety. | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Outlet Header | 84 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. Forced outage. Life Safety. | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Tubes | 85 | 30 | Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | D | High | Creep, fatigue and stress corrosion cracking damage, wall thinning due to corrosion and pitting and DMW failures. Unit shutdown | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Lower) | 86 | 30 | Creep, OD/ID corrosion, ID pitting and sagging. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | D | High | Tube failure due to creep and Creep, OD/ID corrosion, ID pitting. Unit shutdown | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989) | 87 | 30 | Creep, OD/ID corrosion, ID pitting and stress corrosion cracking | (10) | Inspections are required to assess the remaining life. | 2 | C | Med | 2 | D | High | Creep, fatigue and stress corrosion cracking damage, and wall thinning due to corrosion and pitting. Unit shutdown | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage) | 88 | 30 | Creep, OD/ID corrosion, ID pitting and stress corrosion cracking | 10 | This section is relatively new and could meet the desired life. | 1 | C | Low | 1 | D | Low | Creep, fatigue and stress corrosion cracking damage, and wall thinning due to corrosion and pitting. Unit shutdown | Inspect and maintain. |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | N/A | 89 | 33 | Thermal/mechanical fatigue; creep, creep fatigue; corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Unit 1 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations. | 3 | D | High | 3 | D | High | Pipe and/or weld failures at potentially high stress locations Forced outage. Life Safety. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations. |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | N/A | 90 | 33 | Not addressed in detail. Thermal/mechanical fatigue; creep, creep fatigue; corrosion. | (5) | Additional inspections required to assess the remaining life. | 3 | C | Medium | 3 | C | High | Steam erosion - unintended flow to turbine. Material failure and rupture. | Inspection and refurbish or replace. |
| 1296 | 6690 | 6699 | 6701 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | N/A | 91 | 33 | Not addressed in detail. Thermal/mechanical fatigue; creep, creep fatigue; corrosion. | (2) | Safety issue. End of life. | 2 | B | Medium | 3 | C | High | Mechanical failure. Steam leak. Personal injury. | Replace |

### 8.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 1 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result, several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30. The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also includes two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

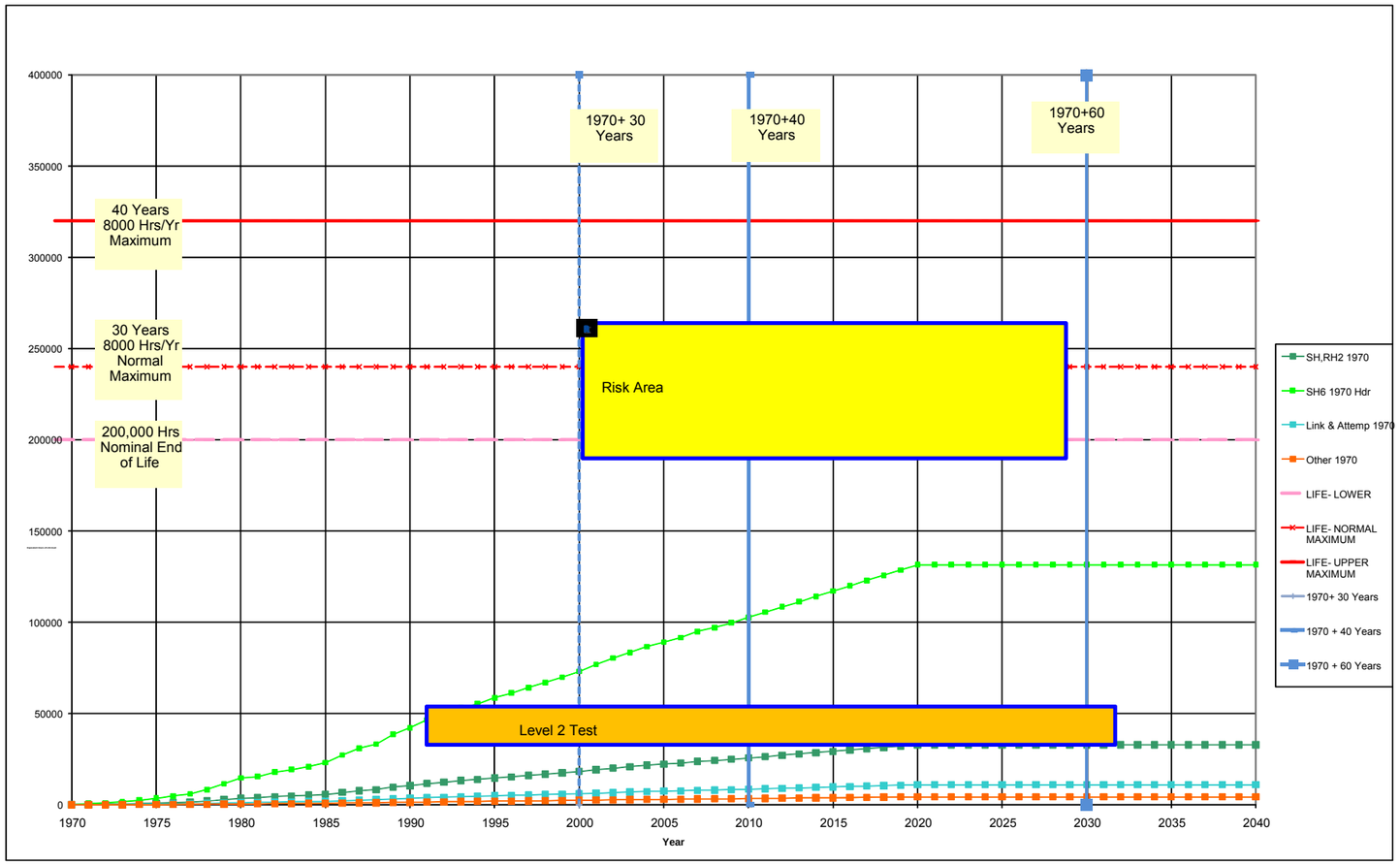



**FIGURE 8-10 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (BOILER HEADERS AND COMPONENTS OUTSIDE THE FLUE GAS PATH)**

The header life curves indicate that the remaining life (RL) of the Unit 1 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature, similar to the boiler headers, and to the material properties of the steam lines. Details are included in Appendix 33.The life curves are plots on the y-axis of current and projected “consumed equivalent life hours” based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life).

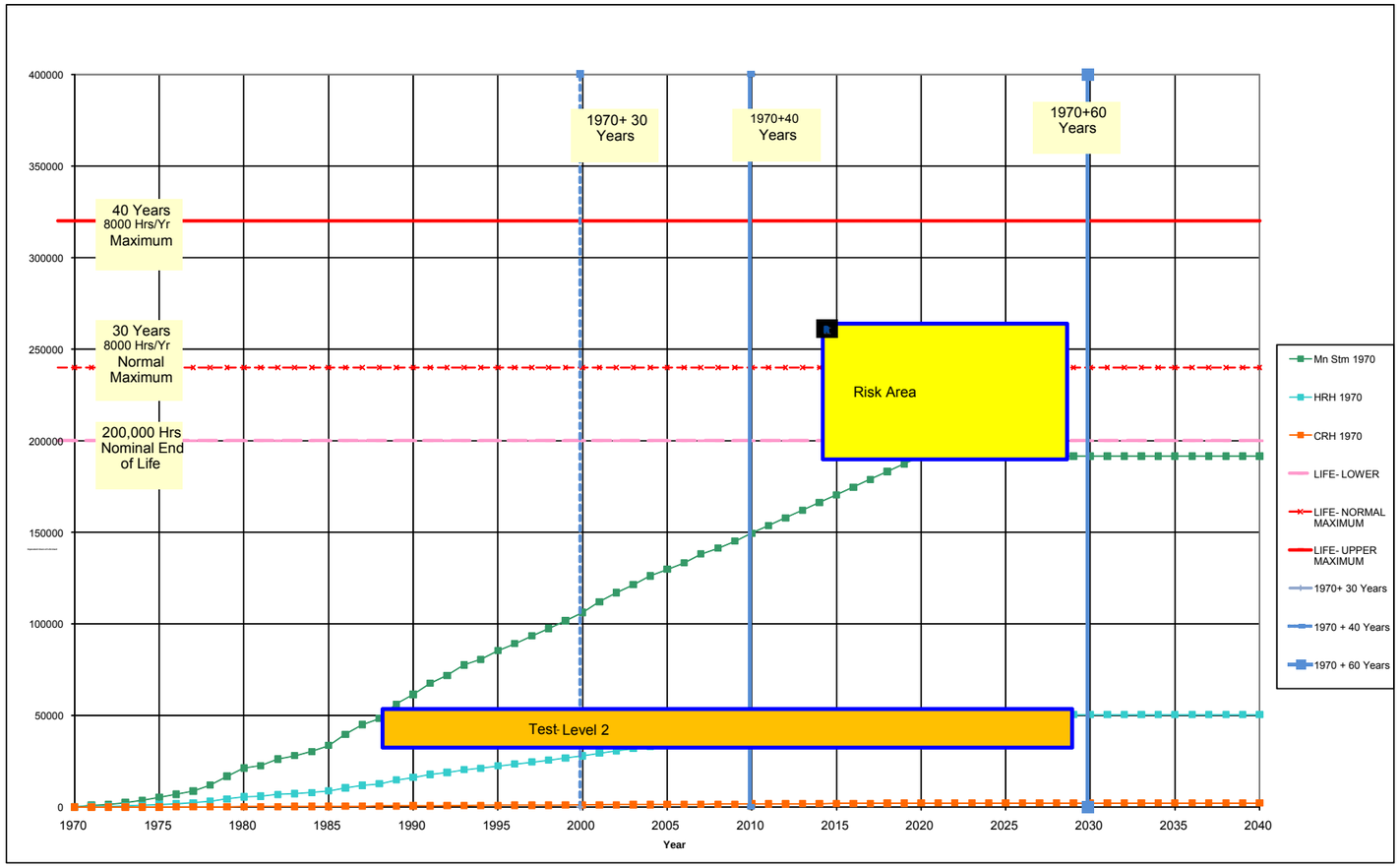



**FIGURE 8-11 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (HIGH PRESSURE AND TEMPERATURE STEAM LINES)**

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 1 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that both the main steam and hot reheat steam lines exceed EPRI’s 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 1 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium,

moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It is shows the current status of the boiler blowdown tank, which is both a life issue and a safety issue. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

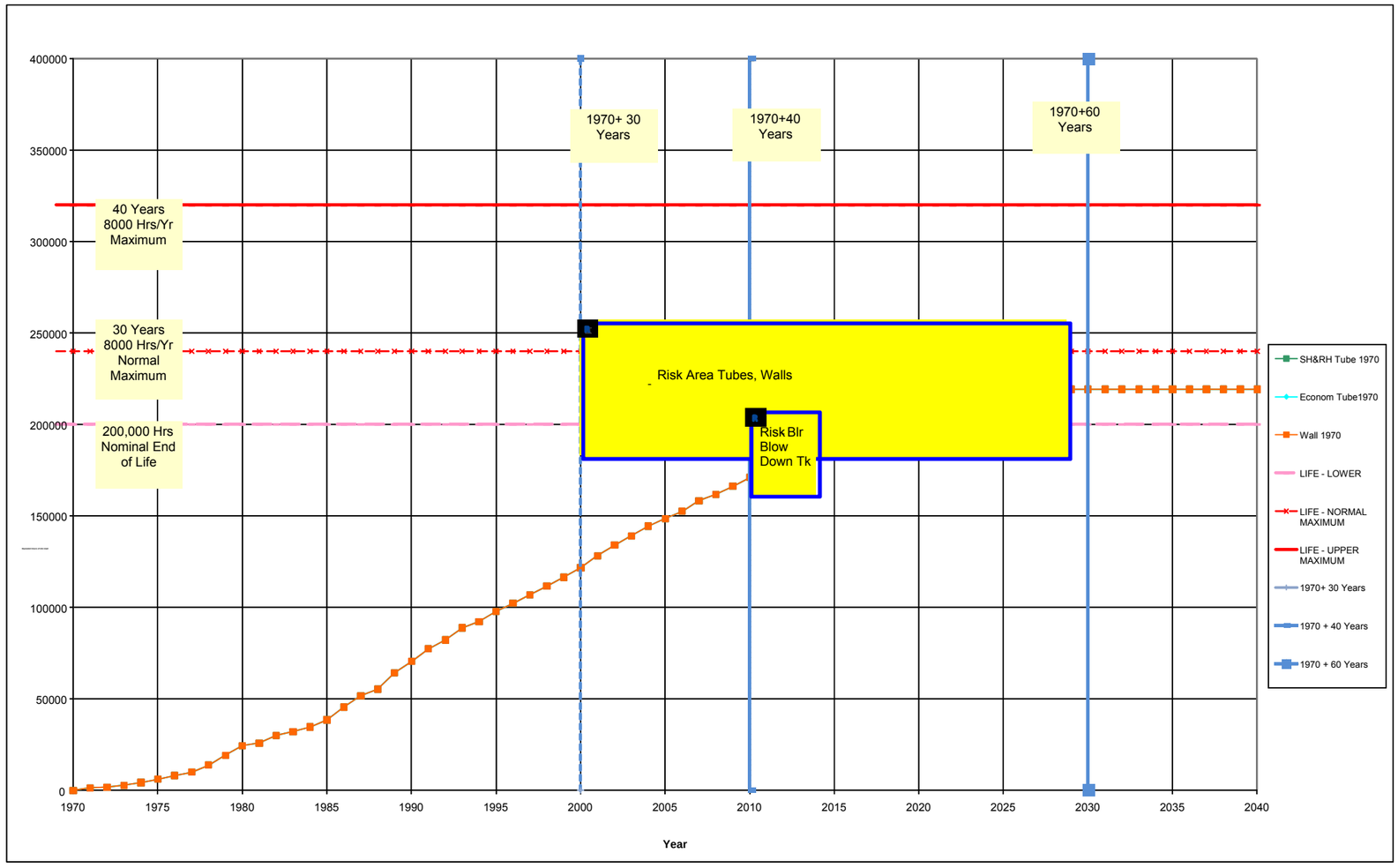



**FIGURE 8-12 LIFE CYCLE CURVE –UNIT 1 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS, BOILER BLOWDOWN)**

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

### 8.2.1.8 Level 2 Inspections – Unit 1 Boiler System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-30 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-30 LEVEL 2 INSPECTIONS – UNIT 1 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | None | 44 | 30 | Costs consolidated here. See boiler section for details. | 2012 | 2 | $1,433 |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Upper WW Headers | 45 | 30 | Inspection of selective flat end welds. External visual and thickness measurement. | 2012 | 3 | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Riser Tubes | 46 | 30 | Inspection of selective riser tubes for corrosion fatigue cracking. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Lower WW Headers | 47 | 30 | Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Feeder Tubes | 48 | 30 | Inspection of selective feeder tubes for corrosion fatigue cracking. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Downcomers | 49 | 30 | Inspections of thermal/mechanical fatigue damage at the headers support locations. | 2012 | 3 | |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | Waterwall Tubes | 50 | 30 | Assessment of the floor tubes wall thinning. Evaluation of pitting in pitting on the tubes adjacent to burners and on the waterwall slope under the economizer. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Inlet Headers | 51 | 30 | Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 52 | 30 | External visual inspection to ensure that there is no change in the state and/or abnormal movement. | 2012 | 3 | |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | Economizer Tubes | 53 | 30 | Sample tubes removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the Unit economizer tube in Unit 2 in 2005. | 2012 | 3 | |
| 1296 | 6690 | 6699 | 6701 | 6870 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | Steam Drum | 54 | 30 | Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6701 | 6871 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | FURNACE | None | 55 | 30 | No Level 2 required. | | | |
| 1296 | 6690 | 6699 | 6702 | 0 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BLR SUPERHEAT& REHEAT ASS'Y | Superheater Steam Cooled Walls Outlet Header | 56 | 30 | No Level 2 required. | | 3 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Inlet Header | 57 | 30 | No Level 2 required. | | 3 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Outlet Header | 58 | 30 | No Level 2 required. | | 3 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Support Tube Inlet Header | 59 | 30 | Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | | 2 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Platen Inlet Header | 60 | 30 | No Level 2 required. | | 3 | |

Table 8-30 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Space Outlet Header | 61 | 30 | Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2012 | 1 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Superheater Link Piping and Attemperator | 62 | 30 | Inspections for assessment of damage caused by Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking and Corrosion. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 63 | 30 | Inspections to check the presence inside pitting and scaling. | 2012 | 3 | |
| 1296 | 6690 | 6699 | 6702 | 6874 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER SUPERHEATER ATTEMP. | None | 64 | 30 | No Level 2 required. | | | |
| 1296 | 6690 | 6699 | 6702 | 6877 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER ATTEMPERATOR | None | 65 | 30 | No Level 2 required. | | | |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Inlet Header | 66 | 30 | No Level 2 required. | | 3 | |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Outlet Header | 67 | 30 | Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2012 | 1 | |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Reheater Tubes | 68 | 30 | Inspections to assess the extent of the damage due to destructive tube sample analysis to assess the extent of the damage due to creep, OD liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMWs. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Lower) | 69 | 30 | Inspections to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989) | 70 | 30 | Inspections for creep, fatigue, corrosion, pitting and stress corrosion cracking. | 2012 | 2 | |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage) | 71 | 30 | No Level 2 required. | | 3 | |
| 1296 | 6690 | 6699 | 6701 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | N/A | 72 | 33 | No Level 2 required | | | |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | (Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater) | 73 | 33 | Level 2 testing of steam and high pressure feedwater lines. | 2011 | 1 | $395 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | None | 74 | 33 | Level 2 Testing of boiler stop valves as part of Main Steam Lines Program. | 2011 | 1 | $30 |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | None | 75 | 17 | No Level 2 required. Undertake preliminary visual inspection of inaccessible areas subject to roof leaks. | 2012 | 2 | $6 |

### 8.2.1.9 Capital Projects

Table 8-31 below shows the suggested typical capital enhancements that should be considered for the Unit 1 boiler system:

**TABLE 8-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 42 | 30 | Install nitrogen blanketing. No other pending Level 2 or next inspection. | 2013 | 2 |
| 1296 | 6690 | 6699 | 6701 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER F.W. & SAT'D STEAM | N/A | 43 | 30 | None , pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6701 | 6869 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER ECONOMIZER | N/A | 44 | 30 | None, pending Level 2 or next inspection possible new recirc line. | | |
| 1296 | 6690 | 6699 | 6701 | 6870 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER STEAM DRUM | N/A | 45 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6701 | 6871 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | FURNACE | N/A | 46 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 0 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BLR SUPERHEAT& REHEAT ASS'Y | N/A | 47 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 6873 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER PRIMARY SUPERHEATER | N/A | 48 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 6874 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER SUPERHEATER ATTEMP. | N/A | 49 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 6877 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER REHEATER ATTEMPERATOR | N/A | 50 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER REHEATER | N/A | 51 | 30 | Implement addition of RH surface to match design temps and efficiency, subject to decision on Holyrood. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6702 | 322990 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | SECONDARY SUPERHEATER | N/A | 52 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6701 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | N/A | 53 | 30 | Replace tank | 2011 | 1 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER MAIN STEAM LINES | N/A | 54 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT & REHEAT ASS'Y | BOILER STOP VALVE | N/A | 55 | 30 | None, pending Level 2 or next inspection. | | |

### 8.2.2 Asset 6708 – Unit 1 Feedwater System High Pressure (HP) Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6708 #1 Condensate & Feedwater System |
| Sub-Systems: | 6713 #1 High Pressure Feedwater |
| Components: | 7112 #1 HP Heater 4 |
| | 7113 #1 HP Heater 5 |
| | 7114 #1 HP Heater 6 |
| | 8835 #1 Boiler Feed Pump East |
| | 8838 #1 Boiler Feed Pump West |

#### 8.2.2.1 Description

The high pressure (HP) feedwater system servicing Unit 1 contains three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heater is a horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of the HP feedwater heater The main components of the HP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. Tubesheet and channel are made from a single forging. The tubes material for all three HP feedwater heat exchangers is stainless steel SA-688-304.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling zones.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts the steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 1. The pumps are multiple stage barrel centrifugal pumps. Each provides up to 60% of full load flow. They have been in service since 1970, with some upgrades when the unit was uprated in 1988. The pump motors are 4 kV motors, approximately 2000 kW. They directly drive the pumps. There is no variable speed device such as variable frequency drives or fluid couplings.

#### 8.2.2.2 History

The requirements for the Unit 1 generators are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses vary for systems/equipment that has been replaced (specifically the HP5 heat exchangers) are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

| | Unit 1 | | |
|---|---|---|---|
| | **HP-4** | **HP-5** | **HP-6** |
| Year Installed | 1985 | 1987 | 1988 |

#### 8.2.2.3 Inspection and Repair History

With the exception of tube leak testing, there have been no NDE inspections carried out on the currently in service HP feedwater heat exchangers in the past. A long term commitment (life-cycle management plan) is required to diagnose and track all the failures to identify possible remedial actions so as to preclude similar future occurrences, and provides the best chance for optimizing feedwater heaters.

The original Unit 1 HP feedwater heat exchangers were replaced from the years 1985 to 1988. HP-4, HP-5 and HP-6 had about 16, 15 and 14 years of base loaded equivalent operation respectively by the end of year 2009 because the plant does not operate all year around. There would be approximately an additional 6 to 8 years of base loaded plant equivalent operation up to the end forecasted operating period of 2020 required. Hence, the feedwater heat exchangers will exceed the average life expectancy of 20 years before the year 2020. The HP-4 is more critical in terms of operating years and it was not designed for the uprated operating conditions. Level 2 inspections are required in order to assess the remaining life on all the Unit 1 HP feedwater heat exchangers.

The Unit 1 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the BFP motors are at a stage in life where failures or lower reliability may be anticipated.

### 8.2.2.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system – HP feedwater heat exchangers is illustrated below in Table 8-32.

**TABLE 8-32 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6712 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 243 | 23 | All existing feedwater pumps are original equipment, but motors replaced in 1989. | 3a | 200000 (30) | 10 | 2020 | 2010 | | Yes | Yes | 1970/1989 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 244 | 23 | Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2009. | 3a | 200000 (30) | 10+ | 2020 | 2016 | 2016 | Yes | Yes | 1970/1989 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Motor | 245 | 23,25 | Motors installed in 1989. Inspected and tested yearly. | 3a | 200000 (25) | (5+) | 2020 | 2016 | 2016 | Yes | No | 1989 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 246 | 23 | Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2003, planned for 2010. | 3a | 200000 (30) | 10+ | 2020 | 2010 | 2010 | Yes | Yes | 1970/1989 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Motor | 247 | 23,25 | Motors installed in 1989. Inspected and tested yearly. | 3a | 200000 (25) | (5+) | 2020 | 2010 | 2010 | Yes | No | 1989 |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | N/A | 248 | 32,33 | No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC. | 4 | 150000 (25) | (5) | 2020 | 2012 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | N/A | 249 | 32 | Installed 1985. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1985 |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | N/A | 250 | 32 | Installed 1986. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 10 | (20) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1987 |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | N/A | 251 | 32 | Installed 1987. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1988 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system – HP feedwater heat exchangers:

**TABLE 8-33 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6712 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 145 | 23 | Assess potential for variable speed control of BFW pumps. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6712 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 146 | 23 | Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 147 | 23 | Maintain current program of ongoing inspections and overhauls. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 148 | 23 | Maintain current program of ongoing inspections and overhauls. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6713 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | N/A | 149 | 32 | See details below. | | |
| 1296 | 6690 | 6709 | 6713 | 7112 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | N/A | 150 | 32 | Perform Level 2 inspections. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6713 | 7113 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | N/A | 151 | 32 | Perform Level 2 inspections. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6713 | 7114 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | N/A | 152 | 32 | Perform Level 2 inspections. | 2012 | 2 |

### 8.2.2.6 Risk Assessment

Table 8-34 below illustrates the risk assessment for the Unit 1 feedwater systems – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-34 RISK ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6709 | 6712 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 142 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | FW Pump East | 143 | 23 | Seal, bearing, impeller failure. | 10+ | None | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction | Current inspection and maintain. |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Unit #1 FW Pp Motor East | 144 | 23 | Electric fault. | (5+) | None | 1 | C | Low | 1 | B | Low | Pump failure; 50% capability reduction | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | 4 kV Boiler Feed Pump Motor | 145 | 25 | Electrical fault, mechanical fatigue, ops error. | (5+) | None | 1 | C | Low | 1 | B | Low | Loss 60% unit generation for extended time | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | 4 kV Boiler Feed Pump Motor | 146 | 25 | Electrical fault, mechanical fatigue, ops error. | (5+) | None | 1 | C | Low | 1 | B | Low | Loss 60% unit generation for extended time | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | FW Pump West | 147 | 23 | Seal, bearing, impeller failure. | 10+ | None | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction | Current inspection and maintain. |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Unit #1 FW Pp Motor West | 148 | 23 | Electric fault. | (5+) | None | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | Feedwater Discharge | 149 | 33 | Flow Accelerated Corrosion (FAC); thermal/mechanical fatigue cracking; corrosion-fatigue cracking; corrosion. | (10) | Major issue is FAC; No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. | 3 | D | High | 3 | D | High | Piping failure. High energy release. | Conduct sample FAC inspections using EPRI methodology. |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | All HP Feedwater Heaters | 150 | 32 | SCC, Thermal/ mechanical fatigue. | (10) | Life management program is required. | 1 | C | Low | 2 | B | Low | Excessive tube failure event resulting in Turbine water induction. | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | Unit #1 HP Feedwater Heater #4 | 151 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Medium | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | Unit #1 HP Feedwater Heater #5 | 152 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Medium | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety threat. | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | Unit #1 HP Feedwater Heater #6 | 153 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Medium | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Safety threat. | Inspect and maintain. |

### 8.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 1 feedwater system - HP heat exchangers and Unit 1 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the Unit 1 feedwater system HP heat exchangers, individual curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

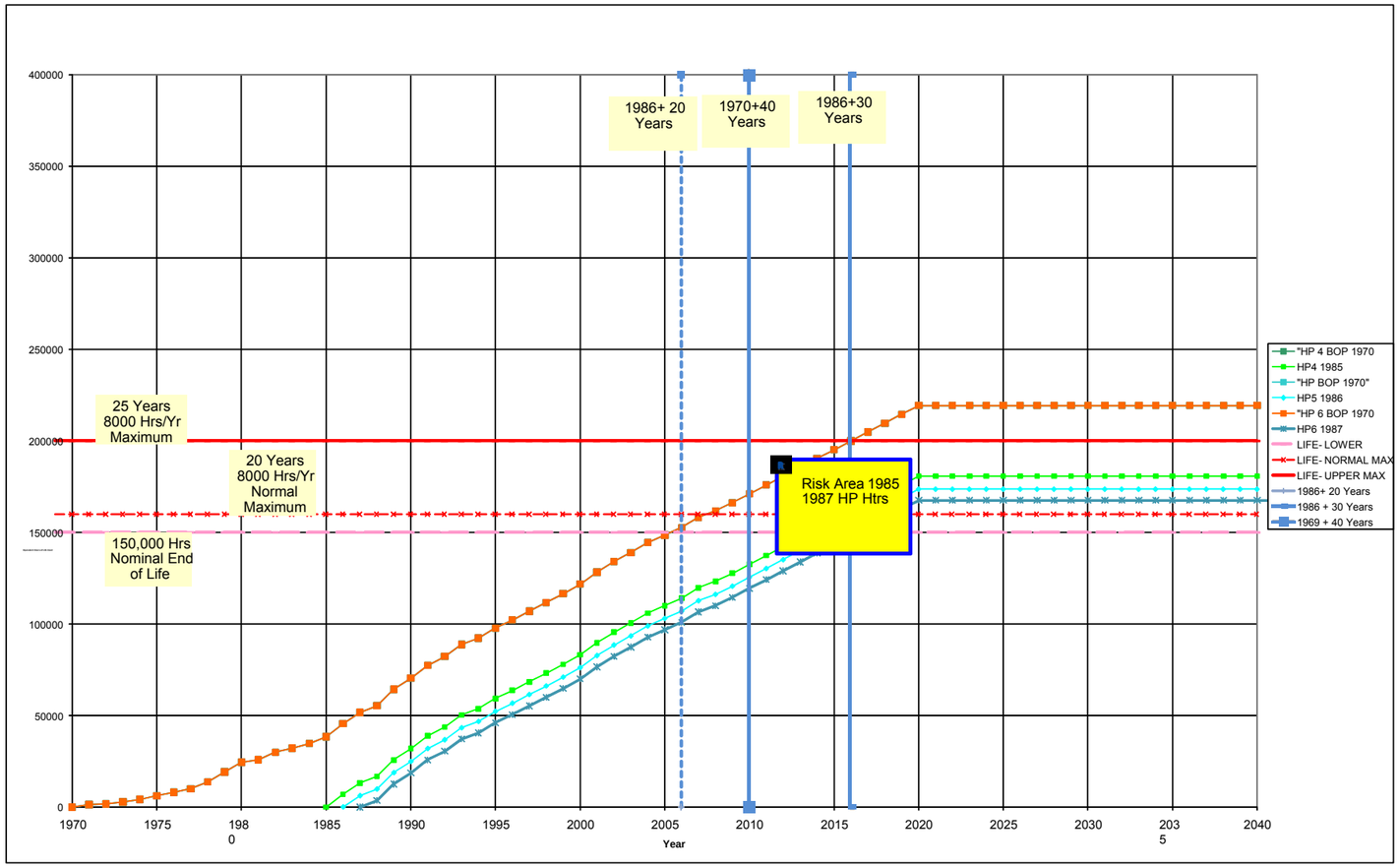



**FIGURE 8-13 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

The curves indicate that the remaining life (RL) of the Unit 1 HP heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2012.

For the Unit 1 Boiler Feed Pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

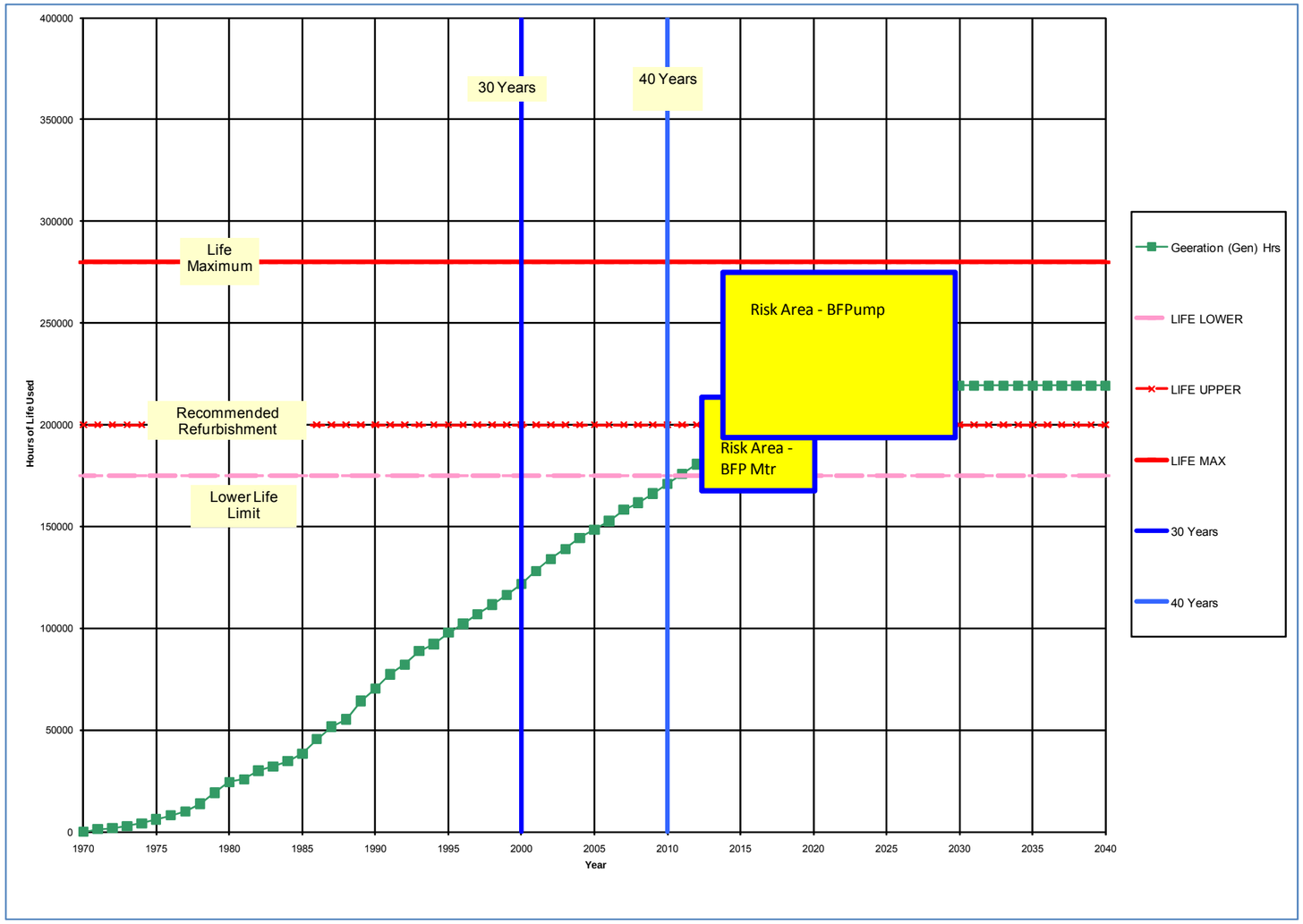



**FIGURE 8-14 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - HP BOILER FEED PUMPS**

The curve indicates that the remaining life (RL) of the Unit 1 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

### 8.2.2.8 Level 2 Inspections – Unit 1 Feedwater System HP Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-35 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-35 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6712 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | None | 129 | 23 | No Level 2 inspections required at this time. Continue program of regular tests and overhauls. | | | |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | None | 130 | 23 | No Level 2 inspections required at this time. Continue program of regular tests and overhauls. | | | |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | None | 131 | 23 | No Level 2 inspections required at this time. Continue program of regular tests and overhauls. | | | |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | None | 132 | 32 | Level 2 of high pressure feedwater heaters summarized here. Level 2 testing of high pressure feedwater lines is included within the costs of the Main Steam Line Item. | 2012 | 2 | $225 |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | None | 133 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | None | 134 | 32 | Assessment of the tube plug map. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | None | 135 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | None | 136 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | None | 137 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | None | 138 | 32 | Assessment of the tube plug map. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | None | 139 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | None | 140 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | None | 141 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | None | 142 | 32 | Assessment of the tube plug map. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | None | 143 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | None | 144 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2012 | 2 | |

### 8.2.2.9 Capital Projects

Table 8-36 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system – HP feedwater heat exchangers:

**TABLE 8-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6712 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 101 | 23 | No capital required. | | |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 102 | 23 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 103 | 23 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required. | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 104 | 23 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 105 | 23 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 106 | 23 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required. | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 107 | 23 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | N/A | 108 | 32 | No capital required. | | |
| 1296 | 6690 | 6709 | 6713 | 7112 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 4 | N/A | 109 | 32 | No capital required. | | |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | N/A | 110 | 32 | Replace HP #5 Heater. | 2013 | 1 |
| 1296 | 6690 | 6709 | 6713 | 7114 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 6 | N/A | 111 | 32 | No capital required. | | |

### 8.2.3 Asset 7053 – Unit 1 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6708 #1 Condensate & Feedwater System |
| Sub-Systems: | 6711 #1 Low Pressure Feedwater System |
| Components: | 7053 #1 Deaerator System (Deaerator and Deaerator Storage Tank) |

#### 8.2.3.1 Description

The deaerator system consists of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 1 deaerator is a horizontal spray type, with the deaerator mounted on the horizontal deaerator storage tank. The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the deaerator.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater in order to lower the potential for corrosion in the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods. The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heater drains are fed to the deaerator. The BFP recirculation is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One end is anchored and the other support is free to allow thermal expansion.

#### 8.2.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

#### 8.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessel internal visual inspections and NDE of selective welds were carried out in accordance with the plant annual outage inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessel as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from year 2001 to 2009:

**Deaerator**

- Cracks in the stainless steel liner;
- Warped stainless liner causing sealing issues for spray nozzles;
- Loose trays;
- Circumferential ridges in the deaerator shell on both the north and south sides; Minor corrosion, pitting, and wall thinning possibly due to flow accelerated corrosion in the bottom of the shell was noted when a section of trays was removed in 2007; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

**Deaerator Storage Tank**

- Corrosion fatigue was found in the storage tank on the inside surface of the shell around the saddle support locations during the 2003 inspection. All damage was removed and the thickness of the tank was restored by pad welding. A semi-circle was cut in the centre gusset plates in the saddles to increase flexibility. Also, the stitch weld between the vessel shell and saddle plate was removed at the centre gusset plate location. Corrosion fatigue was not observed during subsequent inspections at these locations.
- Light pitting has been observed on the inside surfaces in general and especially around the weld seams and in the bottom of shell.
- The manway gasket seating surface was noted to be in poor condition.
- Significant undercut was noted in the first can to can girth weld from the east side during the 2004 outage. The undercut was at a repair weld that was done some time in the past - possibly during fabrication and runs along the bottom one third to one quarter of the shell.
- It was noted in the 2004 outage report that the hot feedwater inlet nozzle to shell attachment welds appeared to be in poor condition. These have not been repaired.

### 8.2.3.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system - deaerator is illustrated below in Table 8-37.

**TABLE 8-37 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 240 | 31 | No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels observed. Wall thinning observed in the bottom of the deaerator shells. Ridges observed may be due to erosion. Undercut observed in storage tank. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | Yes | 1970 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system - deaerator.

**TABLE 8-38 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 135 | 31 | Perform Level 2 inspections. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 136 | 31 | Implement ongoing inspections and performance testing based on industry practices. | 2012 | 3 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 137 | 31 | Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside. | 2012 | 1 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 138 | 31 | Refurbish manway seating surfaces that are in poor condition. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 139 | 31 | Monitor pitting corrosion in the deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerator. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 140 | 31 | Investigate the root cause of the ridges observed in the deaerator. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 141 | 31 | Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank. | 2012 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 142 | 31 | Evaluate condition of spray nozzles that were observed eroding in Unit 3. | 2012 | 2 |

### 8.2.3.6 Risk Assessment

The risk assessment associated with the Unit 1 feedwater system - deaerator, both from a technological perspective and a safety perspective, is illustrated below in Table 8-39.

**TABLE 8-39 RISK ASSESSMENT - UNIT 1 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | Deaerators | 138 | 31 | Corrosion fatigue, thermal fatigue, corrosion & FAC. | (10) | No real life limiting issue as per inspection to date. Additional inspections required. | 3 | B | Medium | 3 | B | Medium | Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure. Forced outage. Life Safety. | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | Deaerators/ Storage Tanks | 139 | 31 | Corrosion fatigue, thermal fatigue, corrosion & FAC. | 10 | No evidence of susceptibly during limited inspection to date. Ongoing monitoring required. | 1 | D | Medium | 2 | D | Low | Forced outage. Life Safety. | Inspect and maintain. |

### 8.2.3.7 Life Cycle Curve and Remaining Life

Figure 8-15 below illustrates the life cycle curve for the Unit 1 Unit 1 feedwater system – deaerator. One curve is used as the major elements of the deaerator are largely of the same age and condition. The life curve is a plot of current and projected operating hours in generation mode only on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

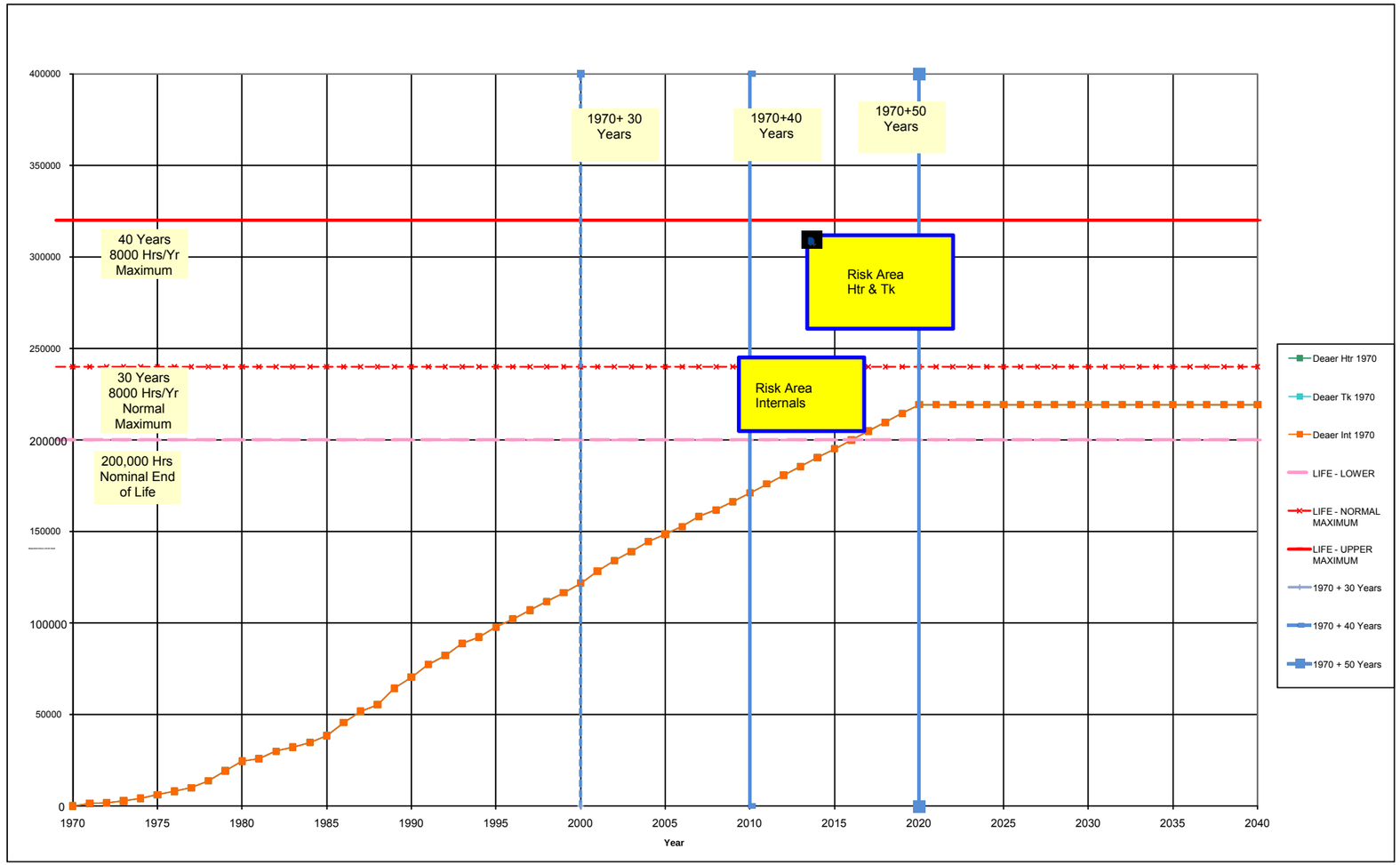



**FIGURE 8-15 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - DEAERATOR**

The curve indicates that the remaining life (RL) of the Unit 1 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. There is however insufficient detailed inspection information of some of the difficult to reach internals to fully assess their condition. A detailed Level 2 inspection in 2012 is recommended to provide information for that assessment.

### 8.2.3.8 Level 2 Inspections – Unit 1 Feedwater System - Deaerator

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-40 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-40 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 121 | 31 | NDE inspection of the areas that were not inspected is required. | 2012 | 2 | $216 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 122 | 31 | Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 123 | 31 | Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface). | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 124 | 31 | Inspection of the tray stack. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 125 | 31 | Inspection of the spray valves. | 2012 | 2 | |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | None | 126 | 31 | Inspections for cracking Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations. | 2012 | 2 | |

### 8.2.3.9 Capital Projects

Table 8-41 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system –deaerator:

**TABLE 8-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | N/A | 98 | 31 | No capital required. | | |

### 8.2.4 Asset 6711 – Unit 1 Feedwater System - Low Pressure (LP) Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendix 24)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6708 #1 Condensate & Feedwater System |
| Sub-Systems: | 6711 #1 Low Pressure Feedwater |
| Components: | 7059 #1 LP Heater 1 |
| | 7066 #1 LP Heater 2 |
| | 7058 #1 LP FW Reserve |
| | 8799 #1 Condensate Extraction System |

#### 8.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 1 contains two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerators.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for closed feedwater heat exchangers.

Two condensate extraction pumps serve Unit 1, driven by 4 kV electric motors. The pumps are original equipment and the motors installed with the unit upgrade in 1989. The pumps draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

#### 8.2.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

#### 8.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, tube plugging maps and history were not available. During interviews with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 1.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps or motors. The motors are electrically checked annually and appear to be in reasonable condition for their age. The motors are however at an age where reliability and failure may be issues in the future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tanks have been undertaken recently, primarily due to concerns associated with enclosed space requirements. Externally, minor surface pitting was evident but no significant problems or leaks were noted.

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### 8.2.4.4 Condition Assessment

The condition assessment of the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components is illustrated below in Table 8-42.

**TABLE 8-42 CONDITION ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 7040 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 146 | 21 | Not reviewed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 8799 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | N/A | 147 | 20 | Limited review. No issues identified. | 3a | (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | N/A | 148 | 20 | Pump installed in 1969 and motor in 1989. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1970/1989 |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | N/A | 231 | 20 | Pump installed in 1969 and motor in 1989. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1970/1989 |
| 1296 | 6690 | 6709 | 6711 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER SYS | N/A | 234 | 24,26 | Not reviewed in detail. No issues identified. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2011 | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | N/A | 235 | 26 | No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections. | 4 | (60) | (20) | 2020 | 2011 | 2011 | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | N/A | 236 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm. | 4 | (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1970 |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | N/A | 237 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm.. | 4 | (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1970 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 feedwater system (and associated condensate extraction system) components - LP feedwater heat exchangers.

**TABLE 8-43 RECOMMENDED ACTIONS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 127 | 20 | See details below. | | |
| 1296 | 6690 | 6709 | 6711 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER SYS | N/A | 128 | 24 | Implement ongoing inspections and performance testing based on industry practices. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7056 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | N/A | 129 | 24 | Perform Level 2 inspections on tanks – thickness checks and internals inspections. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7056 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | N/A | 130 | 24 | Continue a program of ongoing inspections and compare against industry practices. | 2011 | 2 |
| 1296 | 6690 | 6709 | 6711 | 7059 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | N/A | 131 | 24 | Perform Level 2 inspections. | 2011 | 3 |
| 1296 | 6690 | 6709 | 6711 | 7066 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | N/A | 132 | 24 | Perform Level 2 inspections. | 2011 | 3 |
| 1296 | 6690 | 6709 | 7040 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 155 | 21 | See WTP and Polishers. | | |
| 1296 | 6690 | 6709 | 8799 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | N/A | 156 | 20 | Spot check likely critical parts of piping and valving – thickness and corrosion. | 2011 | 2 |
| 1296 | 6690 | 6709 | 8799 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | N/A | 157 | 20 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units, in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 6690 | 6709 | 8799 | 7045 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | N/A | 158 | 20 | Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities. | 2012 | 1 |
| 1296 | 6690 | 6709 | 8799 | 7049 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | N/A | 159 | 20 | Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities. | 2012 | 1 |

### 8.2.4.6 Risk Assessment

Table 8-44 below illustrates the risk assessment for the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-44 RISK ASSESSMENT – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6709 | 0 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 123 | | See details below. | (5) | None | | | | | | | | |
| 1296 | 6690 | 6709 | 7040 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 124 | | Not addressed. Mechanical collapse. | | None | | | | | | | | |
| 1296 | 6690 | 6709 | 8799 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | CE Piping/Valves | 125 | 20 | Weld failure, rupture. | 10 | None | 1 | A | Low | 1 | B | Low | Piping leak; short duration shutdown for repair | Inspect and maintain. |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | CE Pumps | 126 | 20 | Seal, bearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy | Current inspection and maintain. |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | 4 kV Condensate Extraction Pump Motor - A, B | 127 | 25 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | A | Low | 1 | B | Low | Loss 60% unit generation | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | CE Pumps | 128 | 20 | Seal, bearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy | Current inspection and maintain. |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | 4 kV Condensate Extraction Pump Motor - A, B | 129 | 25 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | A | Low | 1 | B | Low | Loss 60% unit generation | Spare and current inspection and maintain. |
| 1296 | 6690 | 6709 | 6711 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER SYS | All LP Feedwater Heaters | 132 | 24 | SCC, thermal/ mechanical fatigue. | (10) | Life management program is required | 1 | C | Low | 1 | B | Low | Excessive tube failure event resulting in Turbine water induction. | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | LP Feedwater Reserve Tanks | 133 | 26 | Corrosion, impingement. | (20) | >10 Years. Inspections are required to confirm | 1 | A | Low | 1 | A | Low | Major Leak, loss condensate | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | LP Feedwater Heater #1 | 134 | 24 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Unit shutdown/htr bypass | Inspect and maintain. |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | LP Feedwater Heater #2 | 135 | 24 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. Unit shutdown/htr bypass | Inspect and maintain. |

### 8.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 feedwater system - LP feedwater heat exchangers is illustrated below. One curve represents both of the low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

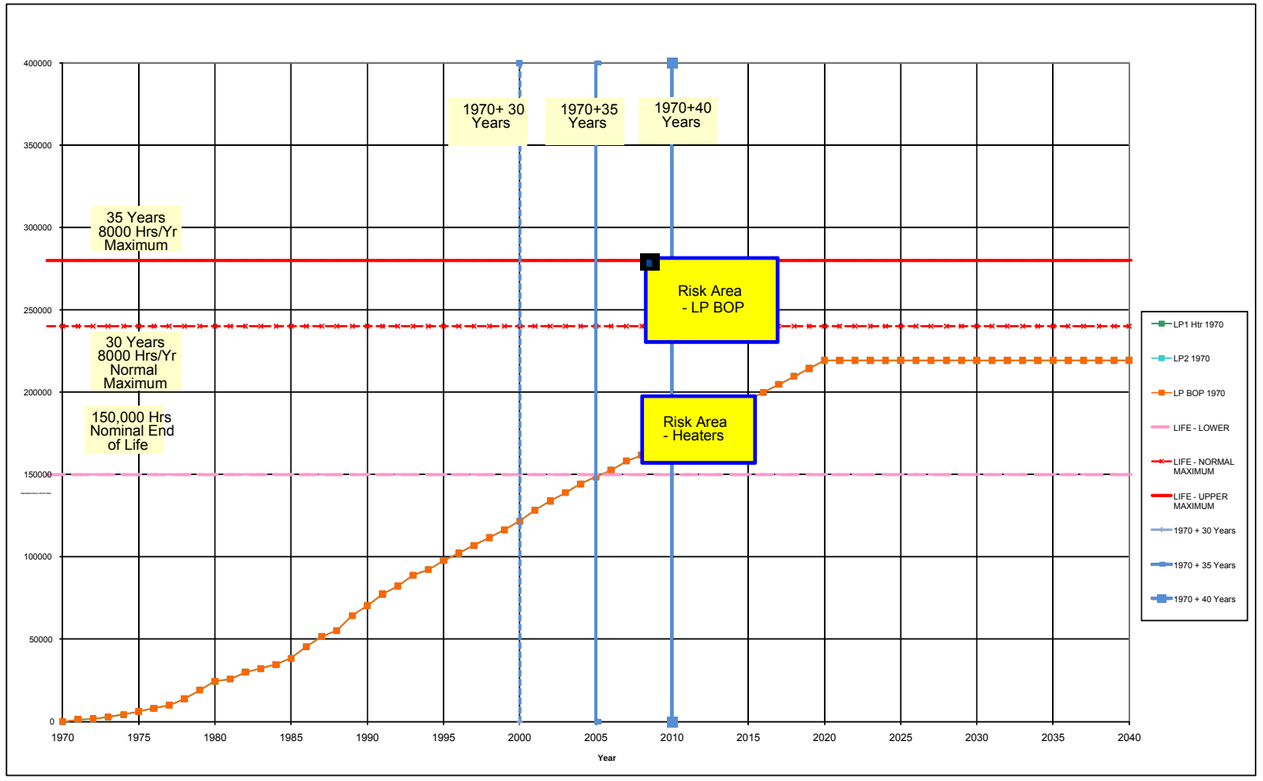



**FIGURE 8-16 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

The curves indicate that the remaining life (RL) of the feedwater system LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 1 condensate extraction pumps and motors is illustrated below. Two curves are used to represent the original equipment pump and the pump motor (upgraded in 1989). The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

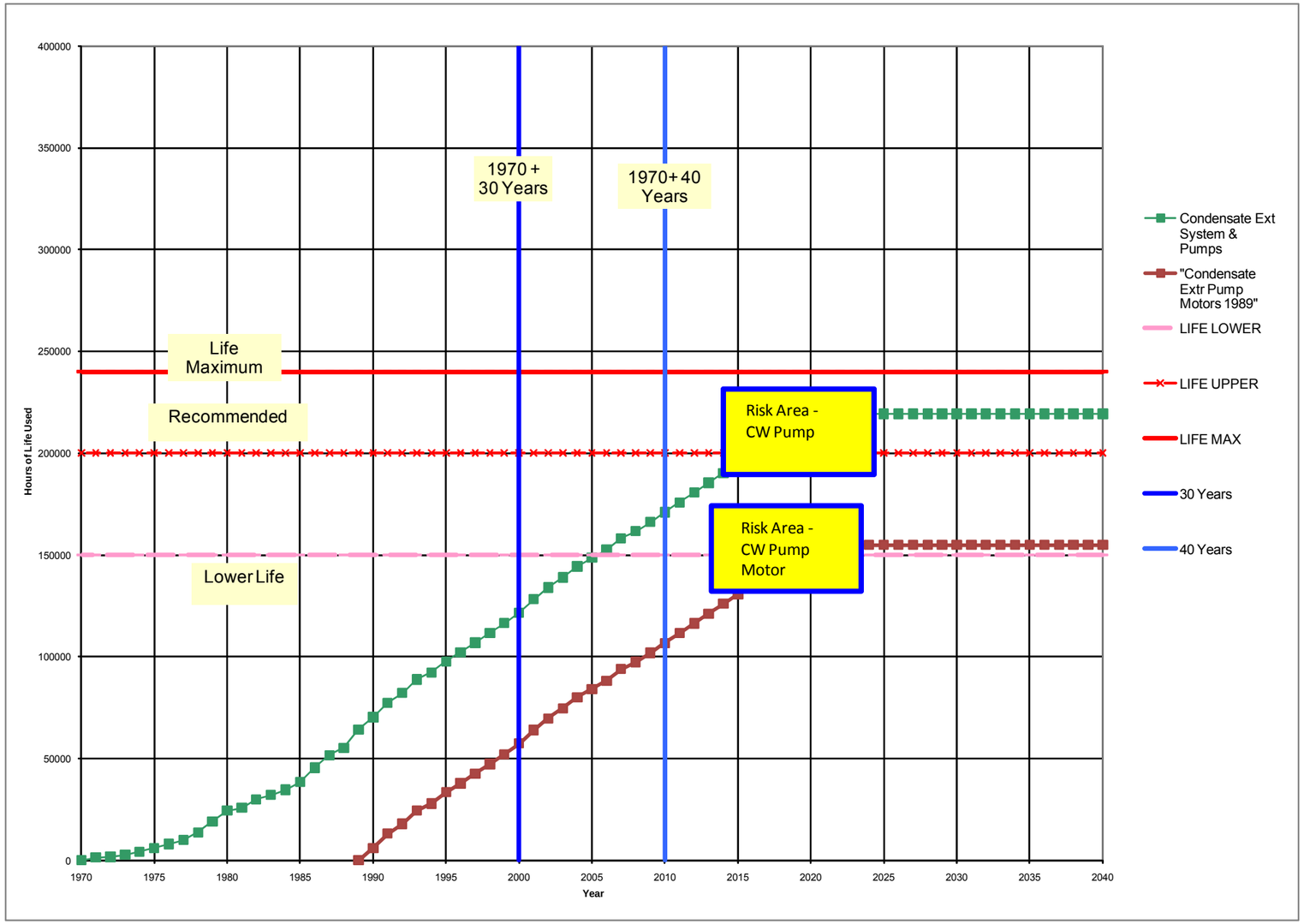



**FIGURE 8-17 LIFE CYCLE CURVE – UNIT 1 FEEDWATER SYSTEM – CONDENSATE EXTRACTION PUMPS AND MOTORS**

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

### 8.2.4.8 Level 2 Inspections – Unit 1 Feedwater System - LP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-45 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-45 LEVEL 2 INSPECTIONS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 0 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | None | 102 | 24 | No Level 2 required. |
| 1296 | 6690 | 6709 | 7040 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | None | 103 | 20 | No Level 2 required. |
| 1296 | 6690 | 6709 | 8799 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | None | 104 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | None | 105 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | None | 106 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. |
| 1296 | 6690 | 6709 | 6711 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER SYS | None | 107 | 24 | |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | None | 110 | 26 | Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection. |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | None | 111 | 24 | Shell side inspections and channel side for the degradation mechanisms. |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | None | 112 | 24 | Assessment of the tube plug map. |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | None | 113 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | None | 114 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | None | 115 | 24 | Shell side inspections and channel side for the degradation mechanisms. |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | None | 116 | 24 | Assessment of the tube plug map. |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | None | 117 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | None | 118 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. |

### 8.2.4.9 Capital Projects

Table 8-46 below shows the suggested typical capital enhancements that should be considered for the Unit 1 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components:

**TABLE 8-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 0 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 85 | | No capital required. | | |
| 1296 | 6690 | 6709 | 7040 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 86 | | No capital required. | | |
| 1296 | 6690 | 6709 | 8799 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | N/A | 87 | 20 | No capital required. | | |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP NORTH | N/A | 88 | 20 | Replace as required per current inspection and overhaul findings. | 2013 | 3 |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | COND EXTRACTION PUMP SOUTH | N/A | 89 | 20 | Replace as required per current inspection and overhaul findings. | 2013 | 3 |
| 1296 | 6690 | 6709 | 6711 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER SYS | N/A | 92 | 26 | No capital required. | | |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | N/A | 93 | 26 | No capital required. | | |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | N/A | 94 | 24 | No capital required. | | |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | N/A | 95 | 24 | No capital required. | | |

### 8.2.5 Asset 271316 – Unit 1 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6691 #1 Turbine & Generator |
| Sub-Systems: | 6739 # 1 Turbine & Condenser |
| Components: | 271316 #1 Condenser |
| | 6895 #2 Condenser Air Extraction |

#### 8.2.5.1 Description

The Unit 1 condenser is shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are sized to allow the unit to run at full vacuum with only one pump operating. Each pump is equipped with a nominally 70 kW, 600 V motor. The condenser also has a stainless steel metal bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied Foster Wheeler in 1969/70.

#### 8.2.5.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Next Major Overhaul/Inspection | 2012 |

The hours associated with the analyses vary from element to element are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

#### 8.2.5.3 Inspection and Repair History

Unit 1 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

A recent tube plug survey completed in 2010 indicated that 5.7% of the condenser tubes are plugged. The 2001 survey indicated that 5.3% of the tubes were plugged at that time. Based on this result, the in-service tube degradation rate of 0.4% over 9 years is very slow. This is also supported by the eddy current testing that was completed in 1998 when 70% of the total condenser tubes were inspected. Results show that 85% of the tubes tested had a wall loss of less than 25%. This is very close to the tube nominal wall thickness and the accuracy of the eddy current testing. These results indicate that the tubes have minimal degradation.

Inspections also confirm that there is no condensate grooving on the tube outside diameter (OD) in the air removing zone of the tube bundle. With the exception of minor wear, the waterboxes and the condenser shell are in good condition.

According to station staff, the steel piping at the inlet and outlet between the condenser and the underground concrete pipes has been replaced but the date was unknown. Some patching is evident on some units.

**Shell & Hotwell:** A review of the 2003 and 2008 inspection reports confirm that both the shell and hotwell are in good condition.

**Waterboxes:** The 2003 report indicated that the water boxes and the epoxy lining were in good condition. However, the condition of the water boxes was not mentioned in the 2008 inspection report.

**Vacuum Pumps:** The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified when achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

### 8.2.5.4 Condition Assessment

The condition assessment of the Unit 1 condenser is illustrated below in Table 8-47.

**TABLE 8-47 CONDITION ASSESSMENT – UNIT 1 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 19 | 22 | Good condition. | 3a | 200000 (40) | 10 | 2020 | 2011 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 20 | 22 | System in good condition. External venting needed. | 10 | 150000 (30) | 5 | 2020 | 2011 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8876 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP NORTH | N/A | 21 | 22 | Near end of life. | 10 | 150000 (30) | (2) | 2020 | 2011 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8877 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP SOUTH | N/A | 22 | 22 | Near end of life. | 10 | 150000 (30) | (2) | 2020 | 2011 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 6733 | 271316 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 23 | 22 | Condition is very good. 2010 tubes plug survey shows 5.7 % of tubes plugged vs 5.3% in 2001. No condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell. The condenser steel piping at inlet and outlet has some patching evident on some units | 3a | 300000 (50) | 20 | 2020 | 2011 | 2012 | Yes | Yes | 1970 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 condenser:

**TABLE 8-48 RECOMMENDED ACTIONS – UNIT 1 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6733 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 26 | 22 | Develop a ongoing program of monitoring CW inlet/outlet pipe conditions | 2011 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 27 | 22 | Perform Level II inspections on waterboxes for Unit 2 at a practical time. | 2011 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP NORTH | N/A | 28 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump | 2011 | 3 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP SOUTH | N/A | 29 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump | 2011 | 3 |
| 1296 | 6690 | 6691 | 6733 | 271316 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 30 | 22 | No action recommended. | | |

### 8.2.5.6 Risk Assessment

Table 8-49 below illustrates the risk assessment for the Unit 1 condenser, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-49 RISK ASSESSMENT – UNIT 1 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 27 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6691 | 6733 | 6780 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 28 | | See details below. | 10 | None | | | | | | | | |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8876 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP NORTH | Condenser Vacuum Pumps & System | 29 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff Decrease while replaced | Maintain, refurbish or replace as required. |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8877 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP SOUTH | Condenser Vacuum Pumps & System | 30 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff Decrease while replaced | Maintain, refurbish or replace as required. |
| 1296 | 6690 | 6691 | 6733 | 271316 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | Condenser | 31 | 22 | Corrosion, erosion. | 20 | None | 2 | B | Low | 2 | A | Low | Major seawater leak to condenser - unit shutdown.. Water cleanup | Inspect and repair. Track history. |

### 8.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 condenser is illustrated below. Only one curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

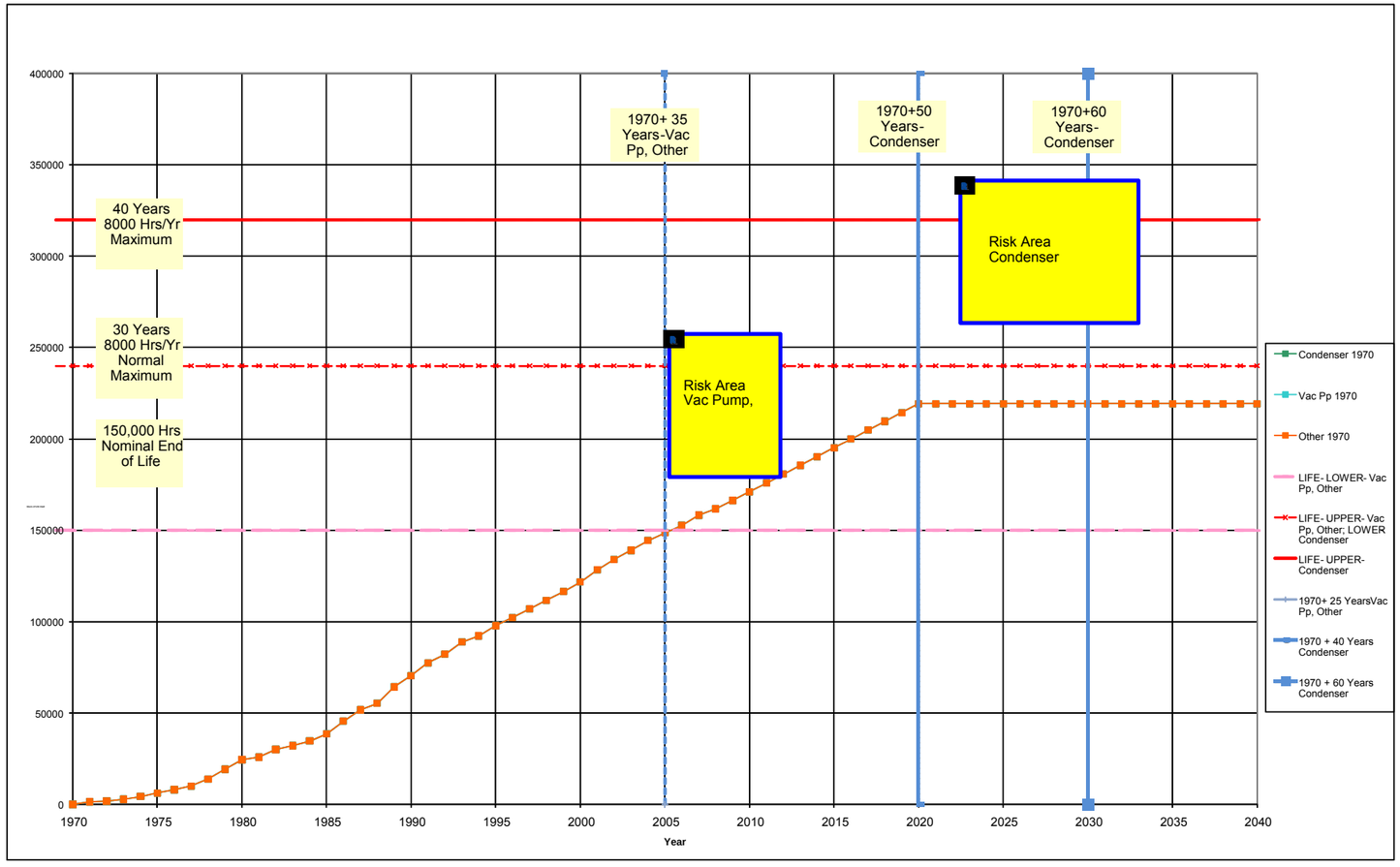



**FIGURE 8-18 LIFE CYCLE CURVE – UNIT 1 CONDENSER**

The curves indicate that the remaining life (RL) of the Unit 1 condenser can easily reach the desired life (DL) 2020 end date for generation. The exception to this, as illustrated by the risk boxes, is the vacuum pumps. These are original equipment, and likely at or near end of life.

### 8.2.5.8 Level 2 Inspections – Unit 1 Condenser

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-50 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-50 LEVEL 2 INSPECTIONS – UNIT 1 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 14 | 22 | NDE spot check inspection of major inlet and outlet pipes. Continue condensers ongoing mtce and inspection. | 2011 | 2 | $4 |
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 15 | 22 | At next turbine and valve overhaul in 2012:<br>- Leak test and update of the tubesheet maps for both the waterboxes.<br>- Check the inlet waterboxes for tubes with water erosion at the tube inlets. Where required, install 10'' plastic inserts into the tubes to protect them<br>- Inspect condenser hotwell internal piping and supports for steam and water erosion. Investigate and repair as necessary<br>- Inspect hotwell drip drains for eroded or missing baffle plates. Replace if eroded or missing | 2011 | 2 | $0 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | None | 16 | 22 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8876 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP NORTH | None | 17 | 22 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8877 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP SOUTH | None | 18 | 22 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 6733 | 271316 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | None | 19 | 22 | No Level 2 required. | | | |

### 8.2.5.9 Capital Projects

Table 8-51 below shows the suggested typical capital enhancements that should be considered for the Unit 1 condenser:

**TABLE 8-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 14 | 22 | See details below. | | |
| 1296 | 6690 | 6691 | 6733 | 6780 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 15 | 22 | Procure spare vacuum pump and motor for Units 1 & 2 (and 3 as practical). | 2012 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8876 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP NORTH | N/A | 16 | 22 | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8877 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | CONDENSER VACUUM PUMP SOUTH | N/A | 17 | 22 | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 6690 | 6691 | 6733 | 271316 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 18 | 22 | No capital required. | | |

### 8.2.6 Asset 8777 – Unit 1 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6699 #1 Boiler Plant |
| Sub-Systems: | 6703 #1 Boiler Air System |
| | 6704 #1 Boiler Gas System |
| | 6705 #1 Boiler Fuel Firing System |
| | 6987 #1 Bir Heavy Oil System |
| | 6990 #1 Boiler Light Oil |
| Components: | 8777 #1 Boiler FD Fan System<br>6943 #1 Boiler FD Fan East<br>6944 #1 Boiler FD Fan West<br>6954 #1 Boiler Steam Air Heater East<br>6955 #1 Boiler Steam Air Heater West<br>6914 #1 Boiler Main Air Heater East<br>6915 #1 Boiler Main Air Heater West |
| | 6917 #1 Boiler Gas Passes<br>6920 #1 Boiler Sootblowing System<br>6933 #1 Retractable Sootblowers<br>6934 #1 Rotary Sootblowers<br>8789 #1 Air Heater Sootblowers |
| | 6988 #1 Boiler Heavy Oil Pump East<br>6994 #1 Boiler Heavy Oil Pump West<br>6995 #1 Boiler Heavy Oil Pump steam, valves and pipe<br>6998 #1 Boiler Heavy Oil Firing<br>6999 #1 Boiler Light Oil Pump West<br>8976 #1 Boiler Light Oil Pump East<br>8977 #1 Boiler Light Oil Pump West |
| | 6979 #1 Boiler Air Supply Seal Air<br>6982 #1 Boiler Scanner Air System |

#### 8.2.6.1 Description

The Unit 1 Combustion Engineering (CE) boiler has two 50% duty 4KV AC constant speed motor driven Howden Forced Draft Fans (East/West) which supply the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure that the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the plant DCS system or manually by the operator if required.

In addition, each FD fan has set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

#### 8.2.6.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |
| | |
| Max Hours Ops – 1986 to Dec 2009 | 121 |
| Max Hrs - 1986 to Dec 2015 | 165 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 174 |

#### 8.2.6.3 Inspection and Repair History

The FD fans, Ljungstrom air heaters, and steam coil air heaters were installed when the unit was constructed in the late 1960's. They are checked annually as part of the boiler inspection program. Generally, all are in reasonable condition considering their age. Issues such as fan component cracking and air heater corrosion are addressed as required. The steam coil air heater was upgraded in 1990 to include a second row of steam coils.

On March 3rd, 2007, the West FD fan self destructed during operation. As a result of the failure, the components that required refurbishment included the fan rotating element, the fan casing, the variable inlet vanes (VIV), and bearing support pedestals. As well, new bearings, sole plates, and alignment shims were installed. The root cause of the forced outage was a vibration related dorsal fin failure. The dorsal fins were re-designed so that they would not be susceptible to a vibration induced failure. During the 2007 outage, the Unit 1 East FD fan dorsal fins were also modified to reflect changes that Howden (the fan OEM) had recommended to the dorsal fin arrangement on the West FD fan. The flow induced vibration still exists on the Unit 1 FD fan system. A change to the ductwork geometry has been identified as being required to reduce or eliminate the turbulence causing the flow induced vibration.

The last outage report completed in 2009 indicates that detailed inspections of this equipment were carried out with minor repairs made to cracks in the ductwork, seals replaced in the Ljungstrom air heaters, some gap discrepancies rectified and an observation that some fins on the steam coil air heater had bent during operation.

The continued use of the much lower sulphur residual fuel oil (0.7% Sulphur) may reduce the corrosion levels noted, especially in the air heaters, and may reduce the maintenance requirements performed by Alstom, depending on a series of operating parameters. The steam coils are pressure tested every year, although no data sheets were reviewed and the inspection dates were not marked on the tubes as had been done previously.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

**Asset 6704 Boilers Flue Gas System, Sootblowers**

The Unit 1 back end flue gas ductwork is original and was installed in 1969. During yearly plant outages, the accessible ductwork has been inspected by Alstom. Reports obtained from the plant indicate that due diligence has been carried out to ensure the structural integrity of the ductwork is maintained and any repairs were completed at the time of inspection. Structural supports were inspected and all have been identified to be in good condition and will last for the foreseeable future.

With regards to the sootblowing system, minor maintenance is carried out during normal operation. Any major work requires a unit shutdown. Boiler fouling and opacity excursions were observed and changes were implemented to improve the sootblowing sequences. With the use of a lower sulphur fuel oil, the implementation of an Intelligent Sootblowing Control system should be considered so that sootblowing is only carried out when needed.

**Asset 6705 Fuel Oil Firing**

Reports at plant regarding the condition of the light and heavy oil systems were not available. However, they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore not considered to be life limiting.

**Asset 6789 Boiler Air Supply Seal Air and Scanner Air**

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained as noted during AMEC's inspection.

### 8.2.6.4 Condition Assessment

The condition assessment of the Unit 1 FD fans and system is illustrated below in Table 8-52.

**TABLE 8-52 CONDITION ASSESSMENT – UNIT 1 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6703 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 72 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 73 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6979 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR FAN | N/A | 74 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6982 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 75 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 6880 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 76 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 77 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 78 | 19, 30 | Inspected yearly and repairs completed as required. Modified dorsal fin arrangement. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 79 | 19, 30 | West fan rotating element, the fan casing, a new dorsal fin arrangement on the air inlet duct, the VIV west ring along with new bearings, a new FD fan motor, new sole plates and shims replaced in 2007. Inspected yearly and repairs completed. | 3a | 200000 (40) | 20 | 2020 | 2011 | | Yes | Yes | 2007 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Motor | 80 | 25 | Inspected yearly and repairs completed as required. Flow induced turbulence in ductwork causing vibration with potential for damage to FD fans and cracks in ductwork. | 3a | (30) | (5) | 2020 | 2011 | | Yes | No | 1988 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Motor | 81 | 25 | A new FD fan motor, new sole plates and shims replaced in 2007. Inspected yearly and repairs completed. Flow induced turbulence in ductwork causing vibration with potential for damage to FD fans and cracks in ductwork. | 3a | (30) | 20 | 2020 | 2011 | | Yes | Yes | 2007 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 82 | 19, 30 | In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6954 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER EAST | N/A | 83 | 19, 30 | In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6955 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER WEST | N/A | 84 | 19, 30 | In 2008 a large number of the fins were bent possibly creating a higher FD fan differential pressure across these coils - status uncertain. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 85 | 19, 30 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6914 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 86 | 19, 30 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6915 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 87 | 19, 30 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6704 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 88 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 89 | 19 | Installed about 1979, with yearly major or minor overhauls. | 3a | 200000 (30) | 10 | 2020 | 2011 | | No | Yes | 1970 |
| 1296 | 6690 | 6699 | 6705 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 90 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | No | Yes | 1970 |
| 1296 | 6690 | 6699 | 6705 | 6990 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 135 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | No | Yes | 1970 |
| 1296 | 6690 | 6699 | 6707 | 0 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | N/A | 136 | | Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation. | 4 | 200000 (30) | (5) | 2041 | 2011 | | No | No | 1970 |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 137 | 17 | SH3 and SH4 hangers found not bearing any load. | 4 | 200000 (30) | 30 | 2041 | 2011 | 2011 | Yes | Yes | 1970 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.
3. The ability of the east and west FD fans to meet a 2020 EOL may be affected if the planned duct reconfiguration is not undertaken.

### 8.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 FD fans (and system):

**TABLE 8-53 RECOMMENDED ACTIONS – UNIT 1 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6703 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 96 | 19,30 | Continue routine inspection, maintenance and overhaul - evaluating air heater hot end baskets; connecting installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes | 2010 | 1 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 97 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR FAN | N/A | 98 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 99 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 6880 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 100 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 101 | 19,30 | Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units, in the event of a failure of an existing unit. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 102 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 103 | 19,30 | No action recommended. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 104 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER EAST | N/A | 105 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER WEST | N/A | 106 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 107 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 108 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8784 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 109 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 111 | 19 | Update obsolete controls as appropriate. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 112 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6705 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 113 | 19 | Continue yearly inspections and repair work. | 2011 | 3 |
| 1296 | 6690 | 6699 | 6705 | 6990 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 114 | 19 | Continue yearly inspections and repair work. | 2011 | 3 |
| 1296 | 6690 | 6699 | 6707 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | N/A | 115 | | Refurbish and replace unit heaters as required. | 2012 | 3 |
| 1296 | 6690 | 6699 | 6700 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 116 | 17 | Visually inspect difficult to access areas. | | |
| 1296 | 6690 | 6699 | 6700 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 117 | 30 | Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6700 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 118 | 30 | Evaluate corrosion on the steel structure and hangers in the boilers penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities. | 2011 | 2 |

### 8.2.6.6 Risk Assessment

Table 8-54 below illustrates the risk assessment for the Unit 1 FD fans (and system), both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-54 RISK ASSESSMENT – UNIT 1 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6699 | 6703 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 93 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 94 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6979 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR FAN | Scanner & Seal Air | 95 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | A | Low | Worst case - Short duration shutdown for repair. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6982 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | Scanner & Seal Air | 96 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | A | Low | Worst case - Short duration shutdown for repair. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 6880 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 97 | | Not Addressed. Mechanical collapse. | 10 | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | | 98 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Unit #1 LP FD Fan | 99 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Unit #1 LP FD Fan | 100 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | 4 kV Forced Draft Fan Motor | 101 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 1 | C | Low | 1 | B | Low | Loss 60% of 1 unit generation + damages | Spare and current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | 5 kV Forced Draft Fan Motor | 102 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 1 | C | Low | 1 | B | Low | Loss 60% of 1 unit generation + damages | Spare and Current Inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8783 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 103 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6954 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER EAST | Unit #1 Steam Preheat Coils | 104 | 19 | Corrosion, erosion, mech distortion. | 10 | None | 1 | A | Low | 1 | B | Low | Short term shutdown for repairs, derated or run at increased impact | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6955 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER WEST | Unit #1 Steam Preheat Coils | 105 | 19 | Corrosion, Erosion, Mech distortion | 10 | None | 1 | A | Low | 1 | B | Low | Short term shutdown for repairs, derated or run at increased impact | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8784 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | APH Ductwork – Gas & Air | 106 | 19 | Corrosion, erosion thinning. | 10 | None | 2 | A | Low | 1 | B | | Short duration shutdown for repair/patch | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6914 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | Unit #1 APH | 107 | 19 | Corrosion, mech failure. | 10 | None | 1 | A | Low | 1 | B | Low | 50% shutdown for mtce and repairs | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6915 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | Unit #1 APH | 108 | 19 | Corrosion, mech failure. | 10 | None | 1 | B | Low | 1 | A | Low | 50% shutdown for mtce and repairs | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6704 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 109 | | See details below. | | None | | | | | | | | |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 110 | | Mechanical failure. | 10 | None | 2 | B | Low | 2 | B | Low | Steam leak. Tube erosion | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6705 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | Fuel Feed System | 111 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | C | Medium | Derate for short period. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6705 | 6990 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 112 | | Mechanical failure, leak. | 10 | None | 3 | A | Low | 3 | B | Medium | Oil spill (hot) | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6707 | 0 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | N/A | 113 | | Mechanical failure. | (5) | None | 3 | A | Low | 3 | B | Medium | Steam leak | Current inspection and maintain. |

### 8.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 FD fans (and system) is illustrated below. Several curves are required to represent the various elements given their different in-service dates and operation history. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

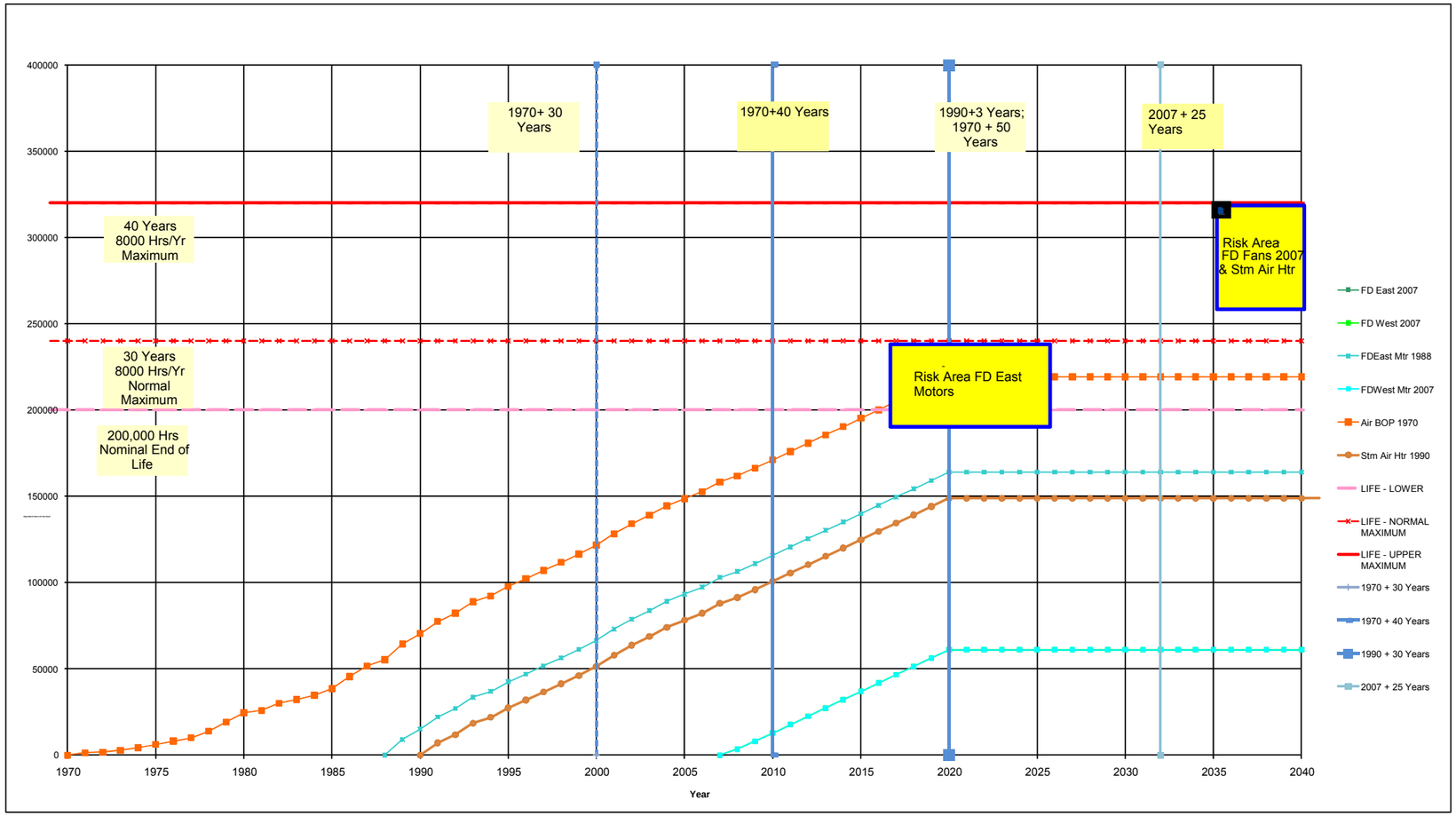



**FIGURE 8-19 LIFE CYCLE CURVE – UNIT 1 FD FANS (AND SYSTEM)**

The curves indicate that the remaining life (RL) of the Unit 1 FD fans (and system) is expected to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

### 8.2.6.8 Level 2 Inspections – Unit 1 FD Fans (and System)

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-55 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-55 LEVEL 2 INSPECTIONS – UNIT 1 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6703 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | | 77 | 19 | Level 2 inspections or testing of duct thickness. | 2011 | 3 | $0 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | None | 78 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6979 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR FAN | None | 79 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6982 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | None | 80 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 6880 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | None | 81 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | None | 82 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | None | 83 | 19 | No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken. | | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | None | 84 | 19 | No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken. | | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | None | 85 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6954 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER EAST | None | 86 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6955 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | #1BOILER STEAM AIR HEATER WEST | None | 87 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | None | 88 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6914 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | None | 89 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6915 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | None | 90 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6704 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | None | 91 | 19 | No Level 2 inspections or testing is required. | 2011 | 3 | $0 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | None | 92 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6705 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | None | 93 | 19 | No Level 2 inspections or testing is required. | 2011 | 3 | $0 |
| 1296 | 6690 | 6699 | 6705 | 6990 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | None | 94 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 6690 | 6699 | 6707 | 0 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | None | 95 | N/A | Not examined. No Level 2 required. | 2011 | 3 | $0 |

### 8.2.6.9 Capital Projects

Table 8-56 below shows the suggested typical capital enhancements that should be considered for the Unit 1 FD fans (and system):

**TABLE 8-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6703 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 57 | 19 | Upgrade air ducts to reduce vibration, improve efficiency. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6703 | 6879 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 58 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6979 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR FAN | N/A | 59 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 6879 | 6982 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 60 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 6880 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 61 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 62 | 25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 63 | 19 | Assess fluid coupling/VFD for BFWP and FDF. | 2011 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 64 | 19 | See details below. | | |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 65 | 19 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 66 | 19 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8783 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 67 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6954 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 68 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8783 | 6955 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 69 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 70 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6914 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 71 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6703 | 8784 | 6915 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 72 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6704 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 73 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 74 | 19 | FD fan ductwork modifications. | 2011 | 3 |
| 1296 | 6690 | 6699 | 6705 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 75 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6705 | 6990 | 0 | 1 | #1 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 76 | 19 | No capital required. | | |
| 1296 | 6690 | 6699 | 6707 | 0 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | N/A | 77 | | New building heating system | 2015-2020 | 2 |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 78 | | No capital required. | | |

### 8.2.7 Asset 6919 – Unit 1 Stack and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6899 #1 Boiler Plant |
| Sub-Systems: | 6714 #1 Boiler Gas System |
| Components: | 6919 #1 Boiler Stack<br>270294 #1 Stack Breeching |

#### 8.2.7.1 Description

The Unit 1 stack was constructed in 1969 from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack.

| Description | Stack Calendar Life | Operating hours/Equiv Op Yrs since Installation to 2009 | Operating hours/Equiv Op Yrs to 2015/2020 |
|---|---|---|---|
| Unit 1 Stack | 44 | 166,000 (20) | 210,000/220,000 (27) |

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |
| | |
| Max Hours Ops – 1986 to Dec 2009 | 121 |
| Max Hrs - 1986 to Dec 2015 | 165 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 174 |
| | |
| Max Hours Ops – 2007/8 to Dec 2009 | 8 |
| Max Hrs – 2007/8 to Dec 2015 | 54 |
| Max Hrs – 2007/8 to Gen End Date Dec 2020 | 174 |

#### 8.2.7.2 Inspection and Repair History

The Unit 1 stack was built in 1966. Since the original construction, the plant has performed regular PM inspections and completed the suggested repairs. Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seem to suggest that Unit 1 has not been operating below the sulfuric acid dew point. The recent change to a much lower sulphur fuel oil has also reduced the acid dew point, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions. Unit 1 carbon steel liner was replaced in 2000. The inspections also suggest that life should not be an issue for the liner for the next ten years, despite the fact that portions of the liner are in excess of 43 years of age. Unit 1 stack has seen approximately 20 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested during the next stack inspection that some NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The Unit 1 stack breeching, referred to as the East and West stack breeching, is connected to the outlet of each air pre-heater and conveys the hot flue gas to the boiler exhaust stack. The original Unit 1 stack breeching was installed in 1969 and had a rectangular cross section that was constructed from carbon steel plate. It was insulated externally with water tight insulation and metal cladding. The original breeching had a life span of approximately twenty years. During operation, there were numerous problems associated with corrosion that led to a complete replacement in 1989.

The existing Unit 1 stack breeching installed in 1989 also has a rectangular cross section that is constructed from carbon steel plate but is insulated internally on the sides and top with borosilicate (glass) block. The breeching sections are also coated externally with a protective film to inhibit corrosion. In addition, the breeching sections also have a silicate concrete floor.

Early into the Unit 1 operation following the upgrade in 1989, problems associated with cracking of the breeching internal insulating liner and concrete floor began develop. The concrete floor began to crack and the insulation blocks began to fall off the breeching, allowing the flue gas to penetrate the breeching plate where it would then cool and form sulphuric acid condensation causing localized corrosion necessitating plate repairs. As a result, the internal insulation liner and breeching plate has required frequent repairs and relatively high maintenance cost during scheduled Unit 1 annual outages.

Hydro completed thickness scanning on Unit 1 stack breeching steel casing in August 2010. The scan indicated that the casing was generally in good condition but localized areas required steel plate replacement due to corrosion. The current plan is to refurbish the steel casing based on the results of the plate thickness scan, replace the expansion joints and the corroded support structure, and insulate the breeching externally complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. The upgrade will be completed in 2011. Following the upgrade, the stack breeching is expected to be able to make the 2020 generation end date without additional major refurbishment or replacement.

### 8.2.7.3 Condition Assessment

The condition assessment of the Unit 1 stack and breeching is illustrated below in Table 8-57.

**TABLE 8-57 CONDITION ASSESSMENT – UNIT 1 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 140 | 17 | The concrete stacks are in good condition, inspected every three years. | 3a | (60/30) | 30 | 2041 | 2011 | | Yes | Yes | 1970 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Liner | 141 | 17 | The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Unit 1 carbon steel liner was replaced in 2000. | 3a | (60/30) | 10+ | 2041 | 2011 | | Yes | Yes | 1970/2000 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 270294 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | N/A | 142 | 17 | Installed in 1990. The current refractory brick lining in the breeching is cracked, which caused localized corrosion. It is planned to refurbish the breeching and replace the brick refractory with an insulated steel lined duct. | 10 | (30) | 3 | 2020 | 2011 | 2011 | Yes | No | 1989/2011 |

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2011 are not undertaken.

4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

### 8.2.7.4 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 stack and breeching:

**TABLE 8-58 RECOMMENDED ACTIONS – UNIT 1 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6704 | 6919 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 121 | 17 | Paint stack, at least top portions, within next five years. | 2013 | 2 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 122 | 17 | Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners. | 2012 | 1 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 123 | 17 | Continue to make all necessary repairs to deficiencies found in inspection reports. | 2012 | 1 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | N/A | 124 | 17 | Undertake current stack breeching refurbishment, including patching the steel liner, installing external insulation, replacing the corroded support structure and installing an ice protection shelter to protect the new external insulation from falling ice. | 2011 | 1 |

### 8.2.7.5 Risk Assessment

Table 8-59 below illustrates the risk assessment for the Unit 1 stack and breech, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-59 RISK ASSESSMENT – UNIT 1 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #1 Concrete Shell | 116 | 17 | Structural cracking. | 30 | None | 1 | D | Medium | 1 | D | Medium | Structural failure requiring shutdown and Unit outage. | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #1 Stainless Steel Liner | 117 | 17 | Corrosion/failure. | (10) | None | 1 | B | Low | 1 | C | Low | Corrosion causing major leak or failure – major leak requiring repair and Unit outage. | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #1 Carbon Steel Liner | 118 | 17 | Corrosion/failure. | (10) | None | 3 | B | Medium | 3 | C | Medium | Corrosion causing major leak or failure – major leak requiring repair | Current inspection and maintain. |
| 1296 | 6690 | 6699 | 6704 | 6919 | 270294 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | Unit #1 Stack Breeching | 119 | 17 | Corrosion/failure. | 3 | None | 3 | D | High | 2 | B | Low | Corrosion causing major leak or failure – major leak requiring repair and Unit outage. | Repair and maintain. |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 120 | 17 | Mechanical failure. | 30 | None | 1 | D | Medium | 1 | D | Low | Building collapse | Inspect and maintain. |

### 8.2.7.6 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 stack and breeching system is illustrated below. Four curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

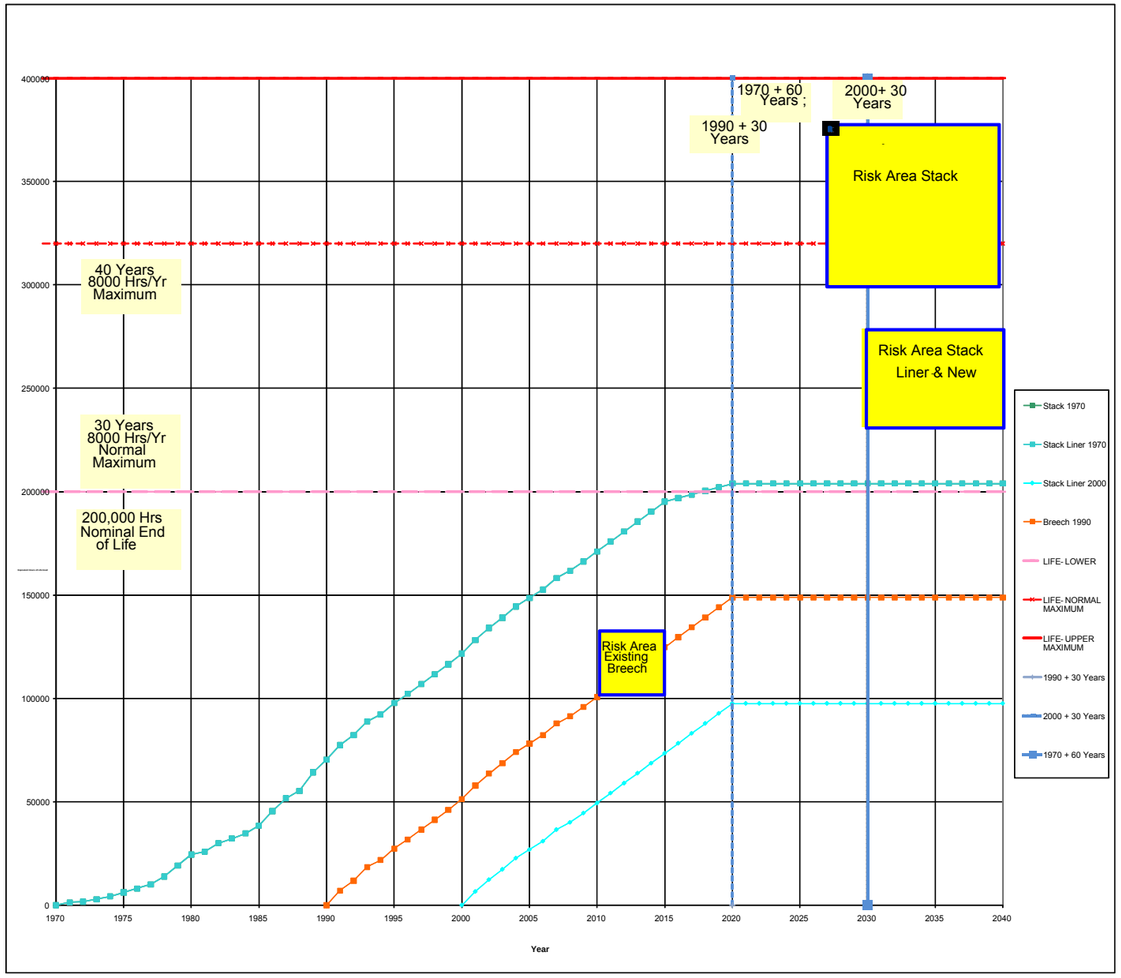



**FIGURE 8-20 LIFE CYCLE CURVE – UNIT 1 STACK AND BREECHING**

The curves indicate that the remaining life (RL) of the Unit 1 stack is may be able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2040 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of poor design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

### 8.2.7.7 Level 2 Inspections – Unit 1 Stack and Breeching

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-60 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-60 LEVEL 2 INSPECTIONS – UNIT 1 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Stacks | 98 | 17 | No Level 2 inspections. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners. | 2011 | | $0 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 270294 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | None | 99 | 17 | No Level 2 required. (Assumes breeching refurbishment undertaken in 2011.) | | | |

### 8.2.7.8 Capital Projects

Table 8-61 below shows the suggested typical capital enhancements that should be considered for the Unit 1 stack and breeching:

**TABLE 8-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6699 | 6704 | 6919 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 81 | 17 | See details below. | | |
| 1296 | 6690 | 6699 | 6704 | 6919 | 270294 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | N/A | 82 | 17 | Refurbish stack breeching. | 2011 | 1 |

### 8.2.8 Asset 6723 - Unit 1 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed below include only those identified as exclusive to plant steam systems.

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 6723 # 1 Electrical & System & Controls |
| Sub-Systems: | 6723 # 1 Electrical & System & Controls |
| Components: | 6693 #1 Turbine Governor System<br>270151 #1 Turbine Supervisory System<br>7173 #1 Burner Management<br>309897 #1 Boiler Protection & Control |

#### 8.2.8.1 Description

The following information covers the Unit 1 electrical and control systems within the plant and its associated buildings.

**Asset 6693 Unit 1 Turbine Governor System**

The system is comprised of an electronic speed governor (GE SpeedTronic Mark V), manufactured by General Electric, and installed in 2003. The governor is complete with protection and monitors speed, metal temperatures, vibration, and steam valve positions into the turbine. A human machine interface (HMI), for operator use, is provided in the control room.

**Asset 7173 Unit 1 Burner Management**

The present burner management system is comprised of a Modicon PLC and Operator Control (HMI), and was installed in 1995. Field wiring in the bottom of the PLC cabinets is the original and was installed in 1969.

The PLC hardware is a Modicon 984 CPU with 800 series I/O and uses Schneider Electric ProWorx software. HMI hardware is a PC with Factory Link Version 6.5 software.

The system controls the operation of the burners and provides start-up and shut-down of the burner and protection of the fuel and air systems.

In 1995, a major upgrade was completed and the Combustion Engineering Cygnus operator consoles were removed and replaced with a PC based HMI console. At this time, the Windows based Factory Link Version 6.5 was installed in the console. During the upgrade, the original Modicon 884 processor was replaced with a 984 processor. The original 800 series I/O modules remained and today these are 25 years old.

**Asset 291668 Unit 1, DCS**

The DCS and auxiliaries related to the steam systems was manufactured by Foxboro, and is an Invensys system installed in 2004 and is considered "state-of-the-art". The processes transferred to the DCS included condensate polishing, water treatment plant, waste water treatment plant, burner management, and boiler P&C. Turbine governor control would likely require upgrades and changes, and the plant has no plans to do so. The Westinghouse panels housing the DCS were installed in the late 1980's, and new cabling was installed at that time. The original system was hard-wired but was later upgraded to a Westinghouse system.

**Asset 309897 Unit 1, Boiler Protection & Control**

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes.

During initial migration from the original Bailey system to Westinghouse WDPF, field equipment, (switches and transmitters), were eliminated where possible or upgraded to more modern design. Typically, -10 to +10V was replaced by 4-20mA analog, plus the boiler control was upgraded to the current design at that time.

In 2004, the DCS system was again upgraded from the Westinghouse WDPF to the present Foxboro DCS system and control algorithms again were revisited. The Foxboro DCS equipment was mounted within the original Westinghouse WDPF enclosures, where it presently remains.

### 8.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Controls Upgrade | 2004 |

### 8.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a support agreement. Upgrades have been and will be carried out as required. Field adjustments and modifications will continue as necessary.

### 8.2.8.4 Condition Assessment

The condition assessment of the Unit 1 electrical and control systems (including DCS) associated with steam systems is illustrated below in Table 8-62.

**TABLE 8-62 CONDITION ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | N/A | 305 | 6 | Generator & Transformer & Auxiliary Protection and Metering Panels tests in 2005 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2011, 2017, 2023, etc.). | 10 | (40) | 10 | 2041 | 2011 | | No | No | 1970 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 306 | 6 | Breaker overhauls have been carried out, between 1995 and 2007 (See Appendix). All 4160V switchgear is applied within ratings. Overhauls due. Past normal life, extended by overhauls/maintenance. | 10 | (25-30) | 5 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 307 | 6 | There are age and spares problems with the relaying system. | 4 | (30) | 10 | 2041 | | | No | No | 1970 |
| 1296 | 6690 | 6723 | 6693 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 277 | 6 | Maintenance (PM) and corrective actions (CA) are performed as required. Servos are checked annually, due to problems with "dirty" hydraulic lines resulting in blocked pilot strainers. From an electrical and controls point of view, the system is operating well. GE support until 2012-2013 with no guarantee of spares. | 3a | (30) | (10) | 2020 | 2012 | | Yes | No | 2003 |
| 1296 | 6690 | 6723 | 270151 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE SUPERVISORY SYSTEM | TURBINE SUPERVISORY SYSTEM | N/A | 308 | 6 | Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time. | 10 | (25) | 2 | 2020 | | | No | No | 1990 |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 309 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 10 | 2041 | | | Yes | No | 2004 |
| 1296 | 6690 | 6723 | 7173 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 310 | 6 | Major upgrade in 1995 with HMI operator consoles and processor. Original 800 series I/O modules remained. Minor failures only. Annual maintenance inspections and repairs. | 3a | (25) | 10 | 2020 | 2011 | | Yes | Yes | 1995 |
| 1296 | 6690 | 6723 | 309897 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 311 | 6 | Maintenance on an unscheduled basis a number of times per year under a support agreement. Upgrades carried out as required. | 3a | 200000 (30) | 15 | 2020 | | | Yes | Yes | 2004 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 electrical and control systems (including DCS) associated with steam systems.

**TABLE 8-63 RECOMMENDED ACTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 224 | 6 | See details below. | | |
| 1296 | 6690 | 6723 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 225 | 6 | See details below. | | |
| 1296 | 6690 | 6723 | 6722 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 226 | 6 | Assess migrating Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2011 | 1 |
| 1296 | 6690 | 6723 | 291668 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 227 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6721 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 228 | 6 | Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270295 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 229 | 6 | Assess Switchgear, 4160V/600V relaying in UB1 modernization study for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6693 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 230 | 6 | See details below. | | 2 |
| 1296 | 6690 | 6723 | 6693 | 333928 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | HOLYROOD MARK V AUTO SYNC | N/A | 231 | 6 | Assess and implement GE migration of the Turbine Governor System Mark V to the Mark Ve system. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270151 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE SUPERVISORY SYSTEM (TSI) | TURBINE SUPERVISORY SYSTEM | N/A | 232 | 6 | Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011. | 2011 | 1 |
| 1296 | 6690 | 6723 | 7173 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 234 | 6 | Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers to provide continuous status monitoring. Flame Scanners will remain unchanged from its present state. | 2012 | 2 |
| 1296 | 6690 | 6723 | 309897 | 0 | 1 | #1 UNIT GENERATION SERVICES | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 235 | 6 | Maintain the Boiler Protection and Control System current through existing Foxboro migration process infinitum.T16 | 2014 | 1 |

### 8.2.8.6 Risk Assessment

Table 8-64 below illustrates the risk assessment for the Unit 1 electrical and control systems (including DCS) associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-64 RISK ASSESSMENT – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Switchgear, 4160V/600V | 204 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | Relay Room Protection & Control | 205 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | Main Controls | 206 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss of unit. Safety | Current inspection and maintain. |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | DCS | 207 | 6 | Electrical fault, ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit | Maintain. |
| 1296 | 6690 | 6723 | 6693 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | Turbine Governor System | 208 | 6 | Electrical fault, mechanical failure ops error. | (10) | None | 1 | C-D | Low | 1 | C | Low | Loss 1 unit generation, damage to unit. Safety | Upgrade governor system. |
| 1296 | 6690 | 6723 | 6693 | 333928 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | MARK V AUTO SYNC | | 209 | | Not addressed. | | None | | | | | | | | |
| 1296 | 6690 | 6723 | 270151 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE SUPERVISORY SYSTEM | TURBINE SUPERVISORY SYSTEM | Turbine Supervisory System | 210 | 6 | Electrical fault, mechanical fatigue, ops error. | 2 | None | 3 | C | Medium | 3 | C | Medium | Loss 1 unit generation, damage to unit | Refurbish or replace. |
| 1296 | 6690 | 6723 | 6693 | 99000260 | 0 | 1 | #1 UNIT GENERATION SERVICES | #1 UNIT GENERATION SERVICES | INSTALL GOVENOR UNIT 1 - MFG C | | 211 | | Not addressed. | | None | | | | | | | | |
| 1296 | 6690 | 6723 | 7173 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | Burner Management | 212 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | C | Medium, Low | 1 | C | Low | Loss 1 unit generation, equipment damage | Refurbish or replace. |
| 1296 | 6690 | 6723 | 309897 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | Boiler Protection & Control | 213 | 6 | Electrical fault, mechanical fatigue, ops error. | 15 | None | 1 | B | Low | 1 | B | Low | Loss of part of 1 unit generation, equipment damage | Maintain. |

### 8.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

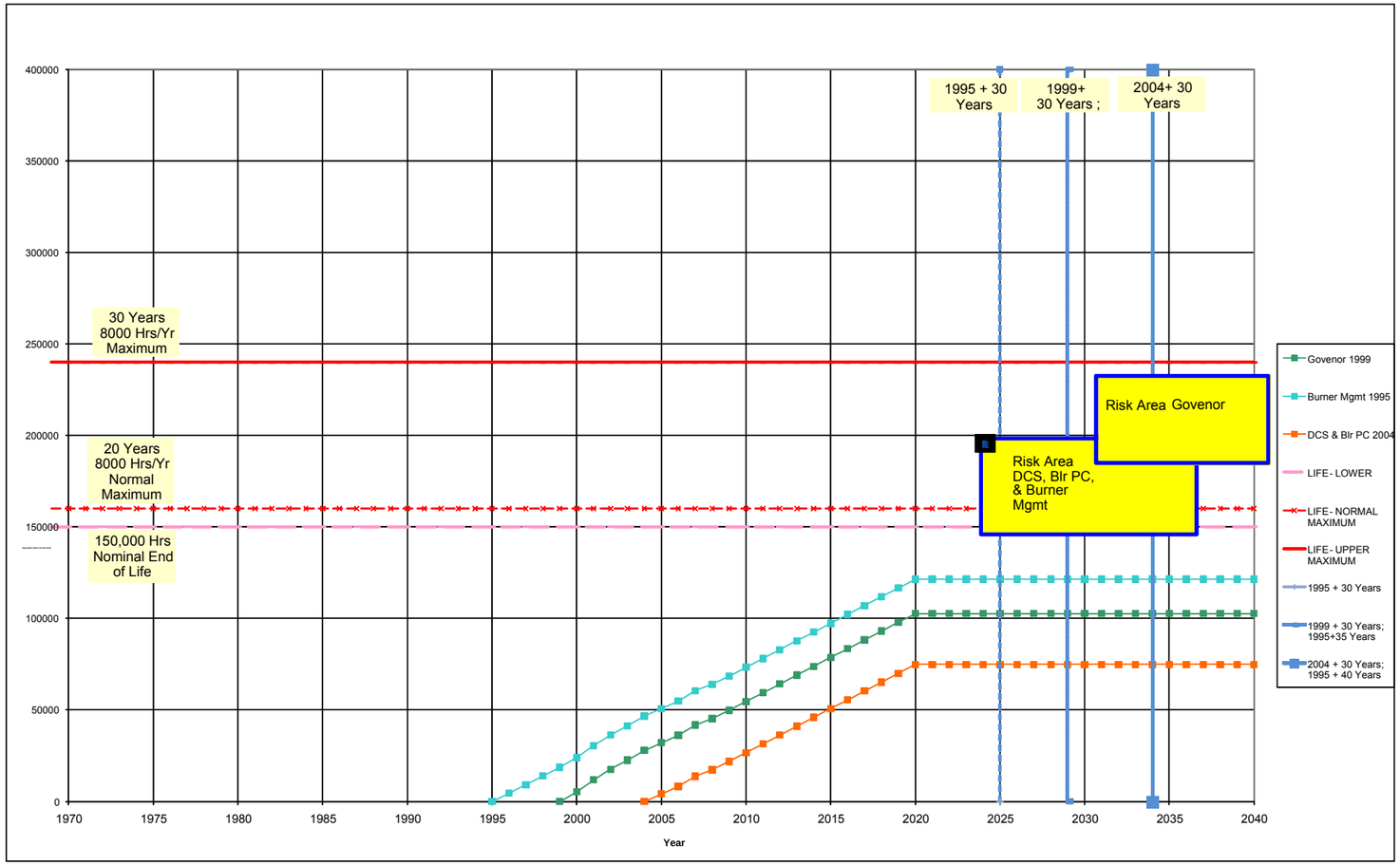



**FIGURE 8-21 LIFE CYCLE CURVE – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 1 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service as per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 8.1.3. It is clear that in order to meet the end date for generation service, some components must be replaced, or in some cases refurbished.

### 8.2.8.8 Level 2 Inspections – Unit 1 Electrical and Control Systems (including DCS) Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-65 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-65 LEVEL 2 INSPECTIONS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | None | 191 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | None | 192 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6693 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | None | 193 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6693 | 333928 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | Holyrood Mark V Auto Sync | None | 194 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6693 | 99000260 | 0 | 1 | #1 UNIT GENERATION SERVICES | #1 UNIT GENERATION SERVICES | INSTALL GOVENOR UNIT 1 - MFG C | None | 195 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 270151 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE SUPERVISORY SYSTEM | TURBINE SUPERVISORY SYSTEM | None | 196 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | None | 197 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | None | 198 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 7173 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | None | 199 | 6 | No Level 2 required. | | | |
| 1296 | 6690 | 6723 | 309897 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | None | 200 | 6 | No Level 2 required. | | | |

### 8.2.8.9 Capital Projects

Table 8-66 below shows the suggested typical capital enhancements that should be considered for the electrical and control systems (including DCS) associated with steam systems:

**TABLE 8-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 0 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | ELEC & CONTROLS SYSTEM | ELEC & CONTROLS SYSTEM | N/A | 166 | 6 | See details below. | | |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTN & CONTROL | RELAY RM PROTECTN & CONTROL | N/A | 167 | 6 | Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. | 2014 | 1 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | N/A | 168 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | N/A | 169 | 6 | Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2014 | 2 |
| 1296 | 6690 | 6723 | 291668 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 170 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 270151 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE SUPERVISORY SYSTEM | TURBINE SUPERVISORY SYSTEM | N/A | 171 | 6 | No capital required. | | |
| 1296 | 6690 | 6723 | 6693 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 172 | 6 | Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processor and modernize operator and maintenance stations. Field wiring and devices remain the same. | 2013 | 1 |
| 1296 | 6690 | 6723 | 7173 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 175 | 6 | Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers. Flame Scanners remain unchanged. | 2011 | 1 |
| 1296 | 6690 | 6723 | 309897 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 176 | 6 | No capital required. | | |

### 8.2.9 Asset 271309 – Unit 1 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 6691 #1 Turbine & Generator |
| Sub-Systems: | 271309 #1 Steam turbine |
| Components: | 6729 #1 Main Steam Chest |
| | 6730 #1 HP Turbine |
| | 6731 #1 IP Turbine |
| | 6732 #1 LP Turbine |
| | 6734 #1 Front Standard |

Note: High energy piping and hangers are addressed within the Boiler Section (Section 8.2.1) under heading Boiler Main Steam Lines (Asset Code 6876). The scope is assumed to include piping and hangers up to the steam turbine.

#### 8.2.9.1 Description

The Unit 1 turbine went into service in 1970. It was originally a 150 MW turbine supplied by General Electrical (GE). The original turbine was a 1970 vintage Lynn D3 model. The turbine is rated to operate at a main steam inlet pressure of 13.0 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine rotating speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate pressure (IP) turbine and one double flow low pressure (LP) turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by three journal bearings. The trust bearing and the turning gear are located in the HP front standard.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located at the stator end-shields. In 1989, the unit was upgraded to produce 175 MW by replacing the HP/IP rotor and the HP/IP steam path components including the HP nozzle block. No changes were made to the LP turbine or the auxiliary equipment.

Unit 1 turbine has an upgraded Mk 5 Electro-Hydraulic Controlled (EHC) governor system with a partial arc steam admission system through 6 control valves. Unit 1 also has one main stop valve (MSV) with an internal pilot valve to control the run up of the turbine to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the

leakage of process steam along the rotor shaft from the turbine casing. There SSR must be able to respond differently at low and high loads.

The turbine auxiliaries considered in this report included:

- The lube oil system;
- The gland steam sealing system, including steam seal regulator;
- The control oil system;
- Steam blow down valve; and
- Power assisted extraction steam non return valves (NRV).

#### 8.2.9.2 History

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Units 1 and 2 Upgrade | 1987 |
| Units 1 and 2 Governor Valves | 2003 |
| Units 1 and 2 HP Nozzle Block Replacement | 2008 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Major Overhaul | 2003 |
| Last Valve (Minor) Overhaul | 2006/2009 |
| Next Major Overhaul/Inspection | 2012 |
| Next Valve (Minor) Overhaul | 2015/2018 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

#### 8.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on six year frequency. As of the year 2003, the overhauls were scheduled to be done every 9 years with the next overhaul scheduled for the year 2012.

The turbine valves overhaul frequency of 3 years was not changed. The last valve overhaul was completed in the year 2009 including a replacement of the HP turbine section nozzle block. The next valve overhaul is scheduled for 2012.

The Unit 1 steam seal regulator is obsolete and in recent years, replacement components have been fabricated locally by copying the original parts. There are issues with the SSR controller binding and sticking during operation. Failure to address the SSR could result in premature deterioration of the steam turbine generator bearings.

The reports indicate that the overhaul work has been done by GE since the year 1999.

**2009 Valve Overhaul**

This was a scheduled valve overhaul. A boroscope inspection of the nozzle block was done at the start of the valve overhaul to check the condition of the partition plates. The inspection confirmed some partition separation and deformation. Based on the Unit 2 2007 incident, and since there was a concern that

some partitions could liberate and do a damage to the turbine steam path, the HP/IP turbine was opened to replace the nozzle block. The following work was performed during the overhaul:

- Installed a new HP nozzle block;
- Dressed out first three HP stage blades. The blades had significant foreign object damage (FOD), possibly by welding slag carried over from the boiler superheater replacement;
- First two HP stage diaphragms were weld repaired and the partition surfaces were built up using the Inconel 82 wire;
- Four out of six control valve (CV) stems and two cross heads were replaced. Stem #4 was cut to allow for valve disassembly. Inconel Stems #2 and #5 were worn beyond allowable tolerances. Inconel Stem #3 was bent beyond specification;
- New Inconel Stems were installed in the #2 and #5 positions;
- The Main Steam Valve (MSV) stem was replaced;
- Both reheat stop valves stems were replaced;
- Fourteen MSV screen rivets that were badly damaged by weld slag from the boiler were replaced; and
- A 2.2 cm (7/8 inch) deep crack in the left combined reheat intercept valve was successfully repaired using a temper bead weld process. This crack was not seen during the last 2006 valve overhaul.

**2006 Turbine Valve Overhaul**

- Replaced various turbine valves stems, seats, and bushings that were damaged, bent, worn out or had excessive run out. CV stem # 4 and #6 were replaced with original material. CV stem #5 was replaced with an Inconel material. (Note that Inconel stems were also installed on CV #3 in 2004 and CV #2 in 2005); and
- A crack in the left reheat valve anti-swirl dam was grinded out and weld repaired. If the proper weld procedure was not followed, the crack could restart in the weld repair area or the weld heat affected zone (HAZ). There may be a connection between this repair and the new large crack found during the 2009 overhaul that was not discovered during this 2006 overhaul (see 2009 overhaul below above).

**2005 Maintenance Upgrade**

Installed the duplex full flow in-line filters in the lube oil system.

**2003 Major Turbine & Valve Overhaul**

- Upgraded the turbine control system to Mark 5 and installed a 60 tooth wheel with 6 speed pickups for turbine control and over speed protection;
- Installed two new proximity probes in bearing #1 and metal thermocouples in bearings 1, 2, and 3;
- Removed eight crack indications in the HP turbine lower outer casing. Grinding was less than 6.3 mm ( 1/4 inch);
- Removed sixteen crack indications in the HP turbine upper outer casing. Grinding was less than 6.3 mm ( 1/4 inch);
- Minor grinding to remove few indications in the HP turbine lower and upper inner casings;
- Minor grinding to remove indications in the LP turbine lower and upper inner casings;
- Re-brazed LP turbine 4th stage tie wire;
- Repaired some reinforcement struts in the LP turbine lower and upper outer casings;

- Replaced various turbine valves stem, seats, and bushings that were damaged, bent, worn out or had run out beyond the allowable limits. CV stems #4 and #5 were replaced due to excessive run out. Stem #3 was broken. Stems #1 and #6 had to be cut out to service the valve; and.
- Replaced bearings in the emergency oil pump, lube oil pump, and turning gear unit.

**1989 HP/IP Turbine Upgrade**

The unit was uprated to produce 175 MW. The following components were replaced:

- New HP/IP rotor with some stages removed;
- Inner casing steam path was changed for both the HP and IP turbine sections; and

The upgrade report was not submitted and has not been reviewed. It is assumed that the inner and outer casings of the HP and IP turbines were not replaced. It is also assumed that the casing joint studs were not replaced.

### 8.2.9.4 Condition Assessment

The condition assessment of the Unit 1 steam turbine is illustrated below in Table 8-67.

**TABLE 8-67 CONDITION ASSESSMENT – UNIT 1 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 33 | 18 | Generally good for age. See details below. | 4 | | | | | | | | |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 34 | 18 | Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and the valves are the original equipment. | 4 | 200000 (30) | 2/5 | 2020 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | N/A | 35 | 18 | Generally turbine and valves in good shape. Extensive foreign object damage (FOD). Turbine casing, high temperature studs and valves are original equipment. HP rotor and HP steam paths that sees the high pressure and temperature service replaced in 1989. Lot of studs with excessive over projection in the HP inner and outer casings | 4 | 200000 (30) | (10) | 2020 | 2012 | 2012 | Yes | No | 1970/1988 |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | N/A | 36 | 18 | Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment. | 4 | 200000 (30) | 10 | 2020 | 2012 | 2012 | Yes | Yes | 1970/1988 |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | N/A | 37 | 18 | Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment. | 4 | 200000 (30) | 10 | 2020 | 2012 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6734 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 38 | 18 | High temperature studs and the valves are the original equipment. Generally HP valves in good shape. | 4 | 200000 (30) | 10 | 2020 | 2012 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | N/A | 39 | 18 | Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and the valves are the original equipment. | 4 | 200000 (30) | 2/5 | 2020 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 40 | 18 | Original equipment, acceptable condition. | 3a | (30) | 10 | 2020 | 2012 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 40a | 18 | Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings. | 10 | (30) | (2) | 2020 | 2011 | 2011 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6778 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 41 | 18 | Original equipment. Not reviewed. | 3a | (30) | 10 | 2020 | 2012 | 2012 | Yes | Yes | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6779 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 42 | 18 | Original equipment. Chain disengagement occurs. Needs refurbishment. | 10 | (30) | (2) | 2020 | 2012 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 6781 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE DRAINS SYSTEMS | N/A | 43 | 18 | Original equipment. Not reviewed in detail. No issues identified. | 4 | (30) | 5 | 2020 | 2011 | 2012 | Yes | No | 1970 |
| 1296 | 6690 | 6691 | 271309 | 270125 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE BLED STEAM SYSTEM | N/A | 49 | 18 | Original equipment. Two of seven pneumatic actuators for extraction steam NRVs were seized. There was substantial rust in the cylinders. | 4 | (30) | 5 | 2020 | | 2012 | Yes | No | 1970 |

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2010/2011

### 8.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 steam turbine:

**TABLE 8-68 RECOMMENDED ACTIONS - UNIT 1 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 33 | 18 | Replace only studs that have mechanical damage, thread deformation or thread wear, irrespective of the temperature service or stud location. | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 34 | 18 | Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out. | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 35 | 18 | Evaluate and resolve the many control valve stem failures. The change of the stem material to Inconel will not solve this problem. Contact Bill Dumbleton (former Saskpower - turbtech@telusnet.net). | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 36 | 18 | Increase extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year. | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 37 | 18 | Follow GE recommended use of N7000 heavy duty metal free anti-seize compound for all turbine casing and valve threaded components. | 2011 | 2 |
| 1296 | 6690 | 6691 | 271309 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 38 | 18 | Implement procedures and temporary filters necessary to reduce/eliminate foreign object impact damage. | 2010 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6729 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 39 | 18 | Work with vendor to identify and resolve key valve issues. Undertake thorough inspection for cracks in both the RH/LH main steam stop valve. | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | N/A | 40 | 18 | Carry out in 2012 Major Overhaul and the 2015 valve only overhaul the following work and inspections:<br>1. Replace the HP diaphragm and spill strip if NL Hydro wants to improve the unit efficiency.<br>2. Inspect the dressed up first 3 HP stage blade surfaces for cracks, wear and tear. Blade replacement is not recommended for relatively minor efficiency loss if unit is operated above 75% MCR.<br>3. Inspect repaired HP diaphragm partition trailing edges (built up using Inconel 82 TIG wire) to check if the Inconel is washing or wearing out. Repair minor damage using Inconel 82, but for extensive damage be prepared to repair the partition off site with 410SS filler material (including stress relief and post weld heat treatment). | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | N/A | 41 | 18 | Estimate HP inner casing studs close to the nozzle block studs that operate above 850 ◦F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850 °F and supply their engineering article on their recommended practice for the high temperature stud replacement) Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | N/A | 42 | 18 | Turn in the HP outer and inner casing studs that have a projection over the allowable limits. Machine seized studs that do not move. Clean, re-tape holes and re-install studs that are not damaged. Asses stud supply options - OEM or other. | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6731 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | N/A | 43 | 18 | Estimate IP inner casing studs close to the nozzle block studs that operate above 850○F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850○F and supply their engineering article on their recommended practice for the high temperature stud replacement) Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6732 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | N/A | 44 | 18 | Perform if possible bore scope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after the seasonal operation. | 2010 | 1 |

Table 8.68 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 6732 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | N/A | 45 | 18 | Carry out in 2012 Major Overhaul and the 2015 valve only overhaul the following work and inspections:<br>1. Inspect and braze broken tie wires on any LP blades to ensure that the designed blade damping condition is maintained.<br>2. Inspect, where possible, L0 and L-1 blade root and wheel steeple surfaces. Repair and replace blade as required.<br>3. Inspect L0 and L-1 blades for water erosion and report. Past reports did not comment on the condition of the blades. Take pictures of the blade surfaces with water wear. | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6734 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 46 | 18 | Undertake normal major inspection checks. | 2012 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6766 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | N/A | 47 | 18 | Inspect for cracks in the RH/LH reheat valves and for crack reinitiation in left hand combined reheat intercept valve body previously repaired.<br>Estimate MSV/CV/RSV and ICV casing studs close to the nozzle block studs that operate above 850○F - see HP a IP inner casings. Since the turbine valves are opened more often and operated at 1000oF, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 48 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2012 | 2 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 48a | 18 | Replace obsolete SSR in 2010/11. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6778 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 49 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2012 | 2 |
| 1296 | 6690 | 6691 | 271309 | 6779 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 50 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2012 | 2 |
| 1296 | 6690 | 6691 | 271309 | 6781 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE DRAINS SYSTEMS | N/A | 51 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2012 | 2 |
| 1296 | 6690 | 6691 | 271309 | 270125 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE BLED STEAM SYSTEM | N/A | 52 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2012 | 2 |

### 8.2.9.6 Risk Assessment

Table 8-69 below illustrates the risk assessment for the Unit 1 steam turbine, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-69 RISK ASSESSMENT – UNIT 1 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 34 | | See details below. | | None | 2 | B | Low | 2 | A | Low | Major seawater leak to condenser - unit shutdown.. Water cleanup | Inspect and repair. Track history. |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | Valves | 35 | | Valve mechanical failure. | (2) | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure | Inspect and maintain. Identify long term solution. |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | High Pressure Turbine diaphragms, nozzle partition plates and turbine blades. | 36 | 18 | Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD). | 10 | None | 2 | B | Low | 2 | A | Low | Turbine lost generation, efficiency, capacity | New nozzle block and some partitions replaced in 2009. Inspect and maintain. Eliminate FOD |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | Intermediate Pressure Turbine diaphragms, and first stage turbine blades. | 37 | 18 | Mechanical failure - SPE and erosion from Foreign Object Damage (FOD). | 10 | None | 2 | B | Low | 2 | A | Low | Turbine lost generation, efficiency, capacity | The diaphragms have been repaired. The blades cannot be repaired. No current condition assessment of the blades. Check condition of the first stage RH blades in 2012 overhaul. Eliminate SP and FOD. |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | Low Pressure (LP) Turbine | 38 | 18 | Chemical/Mechanical failure - LP monoblock integral discs - SCC failure. | 10 | None | 1 | B | Low | 1 | B | Low | Turbine lost generation, efficiency, capacity | Manage the condensate and feedwater chemistry within the ASME guidelines. |
| 1296 | 6690 | 6691 | 271309 | 6734 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE FRONT STANDARD | Governor, Overspeed systems etc. | 39 | 18 | Not addressed in detail. Mechanical or electronics failure. | 10 | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure | Inspect and maintain. Identify long term solution. |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | Valves | 40 | 18 | Valve mechanical failure. | (2) | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure | Inspect and maintain. Identify long term solution. |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 41 | | Not addressed in detail. Mechanical sealing failure. | 10 | None | 1 | C | Low | 1 | C | Medium | Steam leak | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 41a | | Safety risk location under turbine. Condenser vacuum affected - could require trip. | -2 | Obsolete parts. | 3 | C | Medium | 3 | C | Medium | Turbine shutdown, overspeed failure | Replace. |
| 1296 | 6690 | 6691 | 271309 | 6778 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 42 | | Not addressed in detail. | 10 | None | 2 | A | Low | 1 | A | Low | Slow start up | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6779 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 43 | 18 | Not addressed in detail. Mechanical chain failure. | 2 | None | 3 | B | Medium | 3 | A | Low | Turbine bowing without tubing= gear on shutdown | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 6781 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE DRAINS SYSTEMS | N/A | 44 | | Not addressed in detail. Mechanical chain failure. | 5 | None | 2 | B | Low | 2 | B | Low | Shutdown | Inspect and maintain. |
| 1296 | 6690 | 6691 | 271309 | 270125 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE BLED STEAM SYSTEM | N/A | 45 | | Not addressed in detail. Mechanical chain failure. | 5 | None | 1 | C | Low | 1 | C | Low | Shutdown. Possible water induction | Inspect and maintain. |

### 8.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 steam turbine is illustrated below. The two curves represent either the original equipment or that upgraded in 1988 when the turbine was uprated. The unit is due to undergo a major overhaul in 2012. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

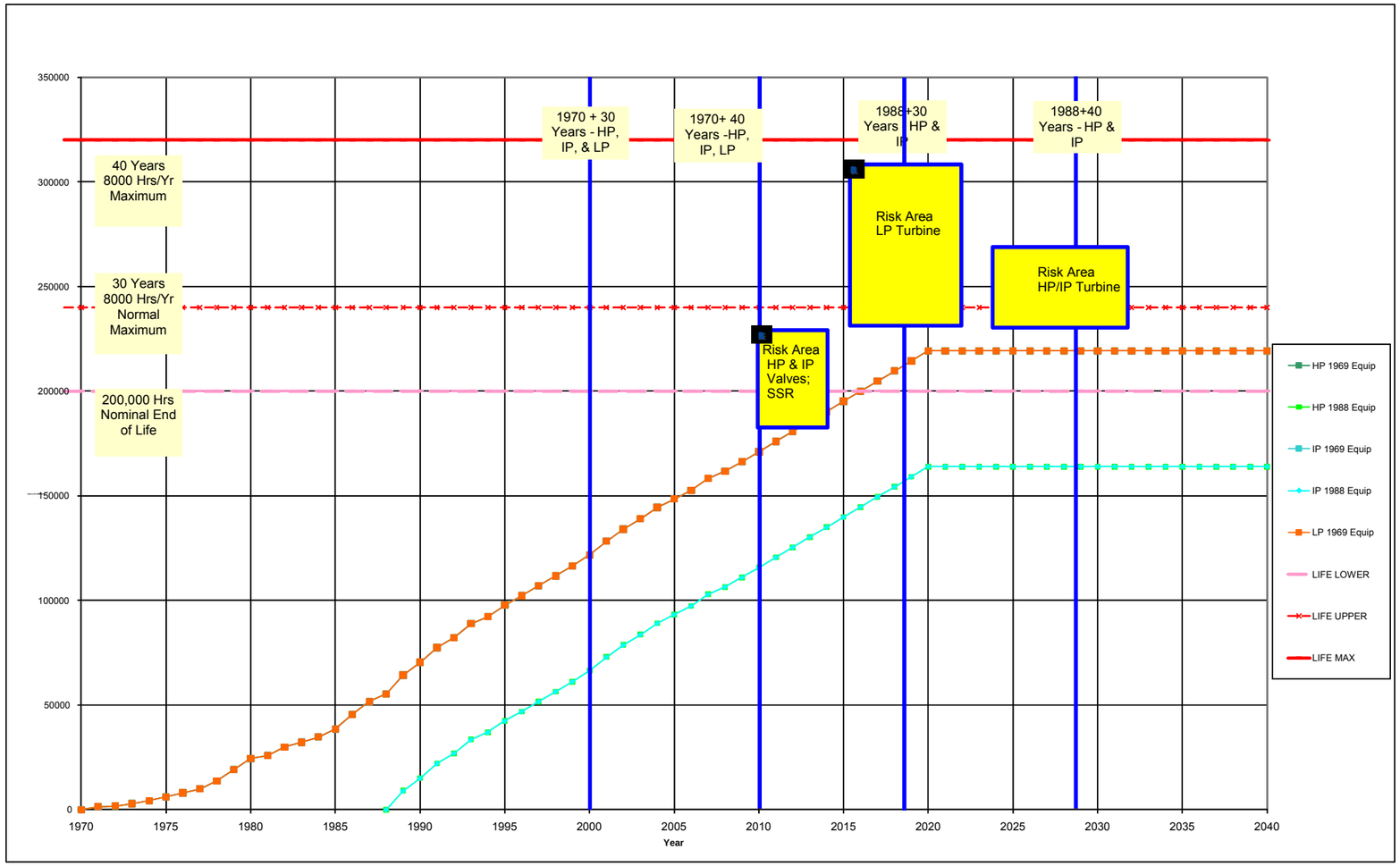



**FIGURE 8-22 LIFE CYCLE CURVE – UNIT 1 STEAM TURBINE**

The curves indicate that the remaining life (RL) of the various elements of the Unit 1 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2012) or to the desired End of Life (EOL) date of 2020. In fact the 2020 end date should be readily achievable. Hence, no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2012 overhaul to confirm the ability to meet the 2020 EOL date. The exceptions to that are the HP and IP valves which continue to have reliability and life issues, the steam seal regulator, as well potentially as high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

### 8.2.9.8 Level 2 Inspections – Unit 1 Steam Turbine

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-70 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-70 LEVEL 2 INSPECTIONS – UNIT 1 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | None | 22 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | None | 23 | 18 | No Level 2 inspections. Actions identified fall under the norms of the overhaul scopes. | 2012 | 1 | $2,311 |
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | None | 24 | 18 | See details below. | | | |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | None | 25 | 18 | Identify and asses studs that operate above 850 ◦F may have reached or are close to the end of their predicted creep life (HP MSV studs). | 2011 | 1 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | None | 26 | 18 | Identify and asses studs that operate above 850 ◦F may have reached or are close to the end of their predicted creep life ( HP inner casing studs close to the nozzle block) | 2011 | 1 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | None | 27 | 18 | Identify and assess those studs that operate above 850 ◦F may have reached or are close to the end of their predicted creep life (IP inner casing studs). | 2011 | 1 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | None | 28 | 18 | LP L0 blades Boroscope: If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door, done after the unit is shut down after every seasonal operation. | 2011 | 2 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6734 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE FRONT STANDARD | None | 29 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | None | 30 | 18 | Identify and asses studs that operate above 850 ◦F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs). | 2011 | 1 | $6 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | None | 31 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 31a | 18 | No Level 2 required. (Assumes replacement in 2010/11 due to obsolecence.) | | | |
| 1296 | 6690 | 6691 | 271309 | 6778 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | None | 32 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 6779 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | None | 33 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 6781 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE DRAINS SYSTEMS | None | 34 | 18 | No Level 2 required. | | | |
| 1296 | 6690 | 6691 | 271309 | 270125 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE BLED STEAM SYSTEM | None | 35 | 18 | No Level 2 required. | | | |

### 8.2.9.9 Capital Projects

Table 8-71 below shows the suggested typical capital enhancements that should be considered for the Unit 1 steam turbine:

**TABLE 8-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | N/A | 28 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 29 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | N/A | 30 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | N/A | 31 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | N/A | 32 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6734 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 33 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | N/A | 34 | 18 | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 35 | 18 | Replace the steam seal regulator. | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6778 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 36 | | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 6779 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 37 | 18 | Refurbish chain and mechanism. | 2011 | 2 |
| 1296 | 6690 | 6691 | 271309 | 6781 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE DRAINS SYSTEMS | N/A | 38 | | No capital required. | | |
| 1296 | 6690 | 6691 | 271309 | 270125 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE BLED STEAM SYSTEM | N/A | 39 | | No capital required. | | |

### 8.2.10 Asset 270182 – Unit 1 Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8715 #1 Unit Generation Services |
| Sub-Systems: | 270182 #1 CW System |
| Components: | 7137 #1 CW Travelling Screens East |
| | 7138 #1 CW Travelling Screens West |
| | 7146 #1 CW Pump East |
| | 7147 #1 CW Pump West |
| | 7134 #1 CW Intake |
| | 7138 #1 CW Discharge to Outfall |

#### 8.2.10.1 Description

The circulating water (CW) systems servicing Unit 1 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.



FIGURE 8-23 UNIT 1 CIRCULATING WATER PUMPS



FIGURE 8-24 UNIT 1 CIRCULATING WATER TRAVELLING SCREENS

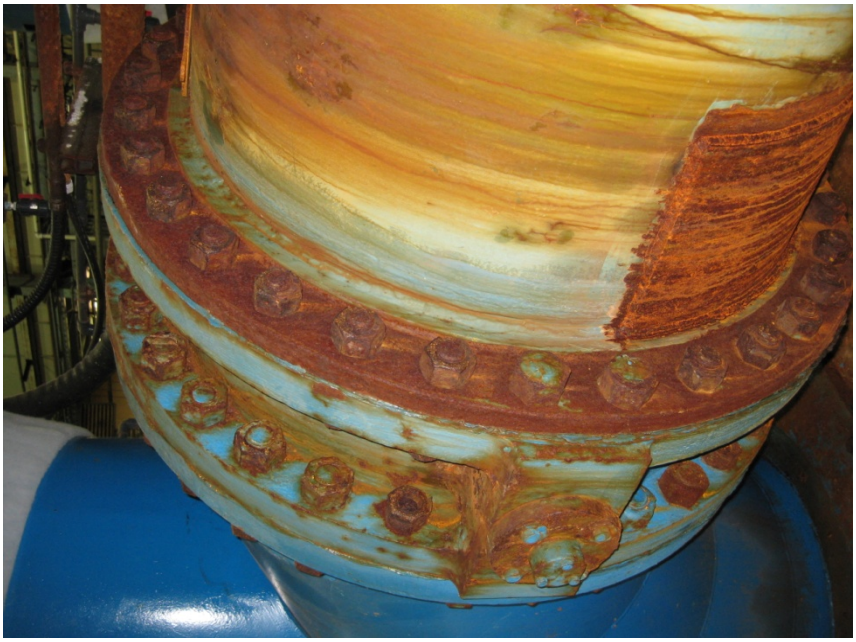


FIGURE 8-25 CIRCULATING WATER PIPE PATCH

### 8.2.10.2 History

The requirements for cooling water system on Unit 1 are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |

| | |
|---|---|
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2012 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 166 |
| Max Hours Generation Ops – to Dec 2015 | 210 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 219 |

### 8.2.10.3 Inspection and Repair History

**Cooling Water Pumps & Motors, Screens, and Piping Systems**

**CW Travelling Screens:** The travelling screen internals have been replaced on Unit 1 in last 5 to 10 years. Interviews suggest that no recent issues have been experienced with this unit. Visual examination confirmed that the Unit 1 screens generally appear to be in good condition.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

**CW Wash Water Pumps and Motors:** An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**CW Pumps:** CW pumps on Unit 1 are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the unit should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 8-72 below.

**TABLE 8-72 MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

**CW Pump Motors:** The CW pumps are driven by 4 kV motors. The motors are the original equipment and are tested electrically every year in accordance with the plant PM process. They are in good condition, but beyond their normal physical life expectation.

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves, and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the Unit 1 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

**Cooling Water System Intake & Discharge:** The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condenser has periodically been dewatered and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per schedule below in Table 8-73.

**TABLE 8-73 PM INSPECTIONS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 8.2.10.4 Condition Assessment

The condition assessment of the Unit 1 CS system associated with steam systems is illustrated below in Table 8-74.

**TABLE 8-74 CONDITION ASSESSMENT – UNIT 1 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID # | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 6782 | 9592 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP SOUTH | T/G COOLING PUMP SOUTH | N/A | 260 | 11,15 | Relatively new AC pumps and motors (no date available). No issue with them. | 3a | (30) | 10 | 2041 | 2012 | | Yes | No | 2000 |
| 1296 | 6690 | 6715 | 6782 | 9593 | 0 | 1 | #1 UNIT GENERATION SERVICES | T/G COOLING PUMP NORTH | T/G COOLING PUMP NORTH | N/A | 261 | 11,15 | Relatively new AC pumps and motors (no date available). No issue with them. | 4 | (30) | 10 | 2041 | 2012 | | Yes | No | 2000 |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 262 | 11 | Generally in good condition, with significant corrosion on major steel pipes and pumps, and valves. | 4 | 200000 (30) | (10) | 2041 | 2011 | | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Concrete pipe from Pumps to Condenser | 263 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe. | 4 | (60) | (20) | 2041 | | 2011 | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Concrete pipe from Condenser to outfall pit | 264 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe. | 4 | (60) | (20) | 2041 | | 2011 | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 265 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | (10) | 2020 | 2012 | | No | No | 1970 |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 266 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | (10) | 2020 | 2012 | | No | No | 1970 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or are not known by AMEC.

### 8.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 1 cooling water system associated with steam systems.

**TABLE 8-75 RECOMMENDED ACTIONS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 270182 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 173 | 11 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7146 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 174 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7147 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 175 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2012 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7146 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 176 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7147 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 177 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Pipe | 178 | 11 | Within the next two to four years, perform a detailed visible inspection, with some NDE spotchecks, of the concrete intake and discharge pipes. | 2011 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Pipe | 179 | 11 | Within the next two to four years, perform a detailed visible inspection, with some NDE spotchecks, of the concrete intake and discharge pipes. | 2011 | 2 |

### 8.2.10.6 Risk Assessment

Table 8-76 below illustrates the risk assessment for the cooling water systems associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 8-76 RISK ASSESSMENT FOR THE UNIT 1 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Unit #1 CW Concrete Pipe to Condenser | 166 | 11 | Concrete racking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair | Inspect and maintain. |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Unit #1 CW Pipe to Outfall Structure | 167 | 11 | Concrete racking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair | Inspect and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | CW Pumps | 168 | 11 | Corrosion- Internal/Ext. | (10) | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | CW Pumps | 169 | 11 | Corrosion- Internal/Ext. | (10) | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | 4 kV Cooling Water Pump Motor | 170 | 25 | Electrical fault, mechanical fatigue, ops error. | (5+) | None | 1 | B | Low | 2 | A | Low | Loss 60% of 1 unit generation | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | 4 kV Cooling Water Pump Motor | 171 | 25 | Electrical fault, Mechanical Fatigue, Ops error, | (5+) | None | 1 | B | Low | 2 | A | Low | Loss 60% of 1 unit generation | Current inspection and maintain. |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Unit #1 Intake Structure | 172 | 11 | Structural cracking; steel corrosion. | (20) | None | 1 | B | Low | 1 | A | Low | Structural failure requiring shutdown | Inspect and maintain. |

### 8.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 1 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 60 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

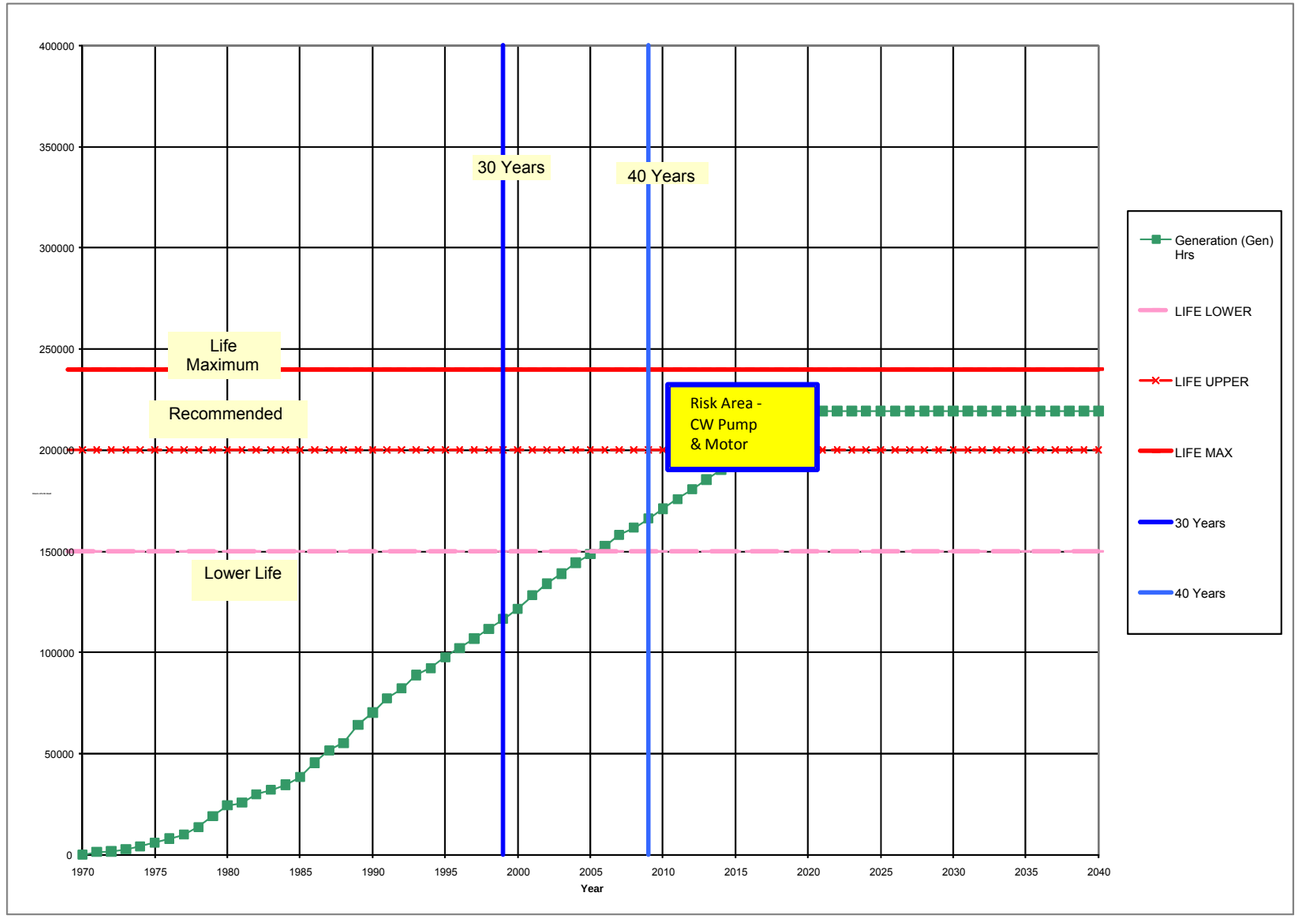



**FIGURE 8-26 LIFE CYCLE CURVE – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 1 cooling water system - associated with steam systems can likely reach the end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motor. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

### 8.2.10.8 Level 2 Inspections – Unit 1 Cooling Water System Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 8-77 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 8-77 LEVEL 2 INSPECTIONS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Concrete Pipe to/from pump to condenser | 156 | 11 | Inspections - dry walk-down and NDE spotcheck. | 2011 | 2 | $6 |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Steel Pipe to/from condenser | 157 | 11 | Clean steel pipe and check thickness measurements. | 2011 | 2 | $6 |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | CW Pumps | 158 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2). No Level 2 on 4 kV motor if current maintenance program continues. | 2011 | 2 | |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | CW Pumps | 159 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2. No Level 2 on 4 kV motor if current maintenance program continues. | 2011 | 2 | |

### 8.2.10.9 Capital Projects

Table 8-78 below shows the suggested typical capital enhancements that should be considered for the Unit 1 cooling water system associated with steam systems:

**TABLE 8-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 1 COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 122 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Concrete pipe from Pumps to Condenser | 123 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE | Concrete pipe from Condenser to outfall pit | 124 | 11 | No capital required. | | |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 125 | 25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 126 | 25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |

# 9 UNIT 2

## 9.1 Unit 2 - Key Systems

### 9.1.1 Asset 7753 – Unit 2 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)



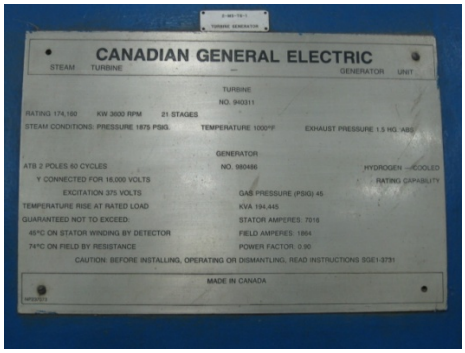



**FIGURE 9-1 UNIT 2 GENERATOR**

Equipment/components covered in this section include the following:

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7638 - #2 Turbine & Generator |
| Sub-Systems: | 7753 # 2 Generator Assembly |
| Components: | 7754 #2 Generator Rotor |
| | 7759 #2 Generator Stator |
| | 7767 #2 Excitation System |
| | 7768 #2 Hydrogen System |

#### 9.1.1.1 Description

The Unit 2 generator is rated at 194,445 KVA, hydrogen-cooled, supplied by Canadian General Electric, Peterborough. It went into service in 1971. The last major inspection was in 2005, after 34 years of service, and is the base reference for this assessment.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. Isolated phase bus delivers the power from the generator to the unit transformer.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent the hydrogen from escaping around the rotating shaft. The seals are pressurised by oil and are located inboard of the bearings. The field windings are directly-cooled by hydrogen, fed via axial sub-slots and radial gas passages in the copper winding. The field windings are supported by retaining rings shrunk onto the ends of the rotor body. The field current is supplied to the field windings via collector rings and brush gear, outboard of the main bearing – there is no steady bearing. There is an unused thrust bearing collar at the turbine end of the generator shaft for future synchronous condenser use.

The excitation to the field is now supplied by an ABB Unitrol static thyristor excitation system, with a fast response automatic voltage regulator to control the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability, to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled exciter fed from the generator terminals, with field flashing for initial energization;
- A seal oil system, with a differential pressure controller to keep the hydrogen contained within the generator;
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator;
- A hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required);
- A scavenging system to remove the hydrogen that becomes entrained in the bearing oil and the seal oil;
- Potential transformers (P.T's), located below the isolated phase bus, measure the generator voltage. Current transformers (CT's) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system continuously monitors the vibration amplitudes at each turbine generator bearing in the control room and alerts the operator to increasing vibration, especially during run-up, load changes, and shut-down. It uses two proximity probes at 45 degrees to the vertical to measure the shaft vibration level; and
- A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings (which are in poor condition - see next item). It also provides supplementary alarms and sequence-of-events monitoring.

#### 9.1.1.2 History

The history and requirements for the Unit 2 generator are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Inspection | 2005 |
| Next Major Overhaul/Inspection | 2014 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 158 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 188 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 212 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 212 | 120 |
| | | |
| Starts Actual - Ops to Dec 2009 | 442 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 674 | 130 |

#### 9.1.1.3 Inspection and Repair History

**Post-2005 Improvements**

- Fast dump of generator hydrogen planned to be added to supplement water sprays on bearings;
- Generator hydrogen dryer replaced;
- Hydrogen purity meter replaced; and
- Plant supervisory TV screens and displays and DAS replaced – alarm settings and states can be checked readily.

**2005 Overhaul**

- Full replacement of the stator slot wedges with top ripple springs;
- Slot couplers re-installed;
- Stator end-winding support system cleaned and re-tightened;
- RTD's checked. 3 are broken and 4 are more than 20% inaccurate (they can only be replaced during replacement of the stator windings);
- Damaged epoxy dowels of fibre inner end-shields – repaired with oversize dowels;
- Rotor dried out and re-tested;
- Collector ring distributors corroded, removed, cleaned and put back;
- Bore seals pressure tested OK;
- Realigned hydrogen seal housing;
- Hydrogen coolers cleaned, and pressure tested OK;

- Installed 4 new cold gas RTD's in stator (GE state they are in wrong locations and will read low);
- Digital multi-functional generator protection relay installed, (for improved winding ground protection, alarms connected, and sequence of events monitoring). Electro-mechanical protection relays retained; and
- Hydrogen seal rings lapped and clearances re-set to lower limits to minimize future oil leaks.

**1999 Overhaul**

- Installed slot couplers for partial discharge monitoring;
- ABB excitation system installed and commissioned;
- Hydrogen seal rings found scored, segments replaced;
- Fan blades NDE checked OK;
- Hydrogen coolers cleaned and inspected – no leaks;
- Collector end hydrogen seal casing realigned to end shield, oversized dowels fitted; and
- Rotor/stator air gaps and fan tip clearances checked.

**1994 Overhaul (details not known)**

- Retaining rings may have been replaced;
- Expect greasing of stator end-windings necessitated re-tightening them; and
- May have re-tightened end-wedges,

**1990 Overhaul**

- Unit up-rated from 174.160 MVA at 207 kPa (30 psi) hydrogen pressure, to 194.445 MVA at 310 kPa (45 psi) hydrogen pressure. New hydrogen seal set installed;
- Stand-off insulators replaced, and lead tube silvered. (Greasing occurred at lead supports due to vibration and oil ingress);
- Retaining rings polished and NDE inspected in situ;
- Pyranol-filled (PCB) excitation transformer drained, cleaned and re-filled with oil (per plant staff but more likely silicon fluid?);
- Installed slot couplers for partial discharge monitoring;
- ABB excitation system installed and commissioned;
- Hydrogen seal rings found scored, segments replaced;
- Fan blades NDE checked OK;
- Hydrogen coolers cleaned and inspected – no leaks;
- Collector end hydrogen seal casing realigned to end shield, oversized dowels fitted; and
- Rotor/stator air gaps and fan tip clearances checked.

### 9.1.1.4 Condition Assessment

The generator and its auxiliary systems are in reasonable good condition for their age.

- Stator core: satisfactory, based on EI-cid results;
- Stator Windings: Poor, based on Megger test and DC hipot test;
- Rotor Forging: Not known. (Appears not checked in past 20 years); and
- Field Winding: Satisfactory, but few details available (concerns are based on repairs made to similar GE rotors).

Details of the sub-systems are presented in the Table 9-1 and in more detail in Appendix 4.

**TABLE 9-1 CONDITION ASSESSMENT – UNIT 2 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | N/A | 11 | 4 | Stator: Core - Satisfactory; Windings - Poor<br>Rotor: Forging - Not known, likely satisfactory; Winding - Satisfactory, but limited information<br>Overhaul required in 2014. | | | | | | | | | |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Core | 12 | 4 | Forging: Not known, likely satisfactory. | 4 | 200000 (40) | (15) | 2041 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Winding | 13 | 4 | Field Winding: Satisfactory, but little information. The field current is not credible - much too low. The field winding temperature is not monitored. No on-line monitoring for shorted field turns (most common indication the rotor needs to be re-wound) is in place. Partial discharge monitoring is not working. The shaft voltage and the shaft ground current are not monitored in operation for harmful currents through the bearing or hydrogen seal. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects. | 4 | 200000 (30) | (10) | 2041 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Core | 14 | 4 | Core - Satisfactory. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore or at the outside flexible mounting. GE reported that EI-cid readings taken before and after the re-wedging of the stator bars in 2005 show no significant core deterioration, and the stator core is fit to be re-wound.<br>The stator winding and core RTD's do not read credible values - too low. | 4 | 200000 (40) | (15) | 2041 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Windings | 15 | 4 | Windings: Poor, requiring rewind. Reported in 2003 major outage to be in very poor condition with two of three phases significantly weaker and insulation weakness (or wetness). It is anticipated that more extensive loosening, fretting, and greasing of the end-windings will be found at the next inspection. Stator winding RTD's do not read credible values - too low. | 4 | 200000 (30) | (10) | 2041 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | N/A | 16 | 4 | Hydrogen cooler, hydrogen dryer, and hydrogen purity meter working well. The hydrogen scavenging system (removing entrained hydrogen from the seal oil) appears less effective than the Unit 3 vacuum system. The hydrogen pressure is low, probably due to hydrogen leaks (causes extra heating of the generator core and windings). Consumption is not recorded. The cold gas temperature is low at 30 °C versus GE minimum 35 °C. | 3a | 200000 (30) | (10) | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 17 | 4 | The horizontal joint of the hydrogen seal assembly was epoxied to prevent hydrogen/oil leakage into the generator, but the risk is high that the hydrogen sealing system has not been successful in preventing oil entering the generator and contaminating the end-windings. | 4 | (30) | (5) | 2020 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | TURB AC SEAL OIL PUMP EAST | N/A | 18 | 4 | Not reviewed in detail - no issues. Aging. Include in Generator overhaul. | 4 | (30) | (5) | 2020 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN AC SEAL OIL PUMP WEST | N/A | 19 | 4 | Not reviewed in detail - no issues. Aging. Include in Generator overhaul. | 4 | 200000 (30) | (5) | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN DC SEAL OIL PUMP | N/A | 20 | 4 | Not reviewed in detail - no issues. Aging. Include in Generator overhaul. | 4 | 200000 (30) | (5) | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN SEAL OIL VACUUM PUMP | N/A | 21 | 4 | Not reviewed in detail - no issues. Aging. Include in Generator overhaul. | 4 | 200000 (30) | (5) | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7773 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN CO2 GAS PURGE SYSTEM | N/A | 22 | 4 | Not reviewed in detail. No issues identified aside from capacity and supply concerns. | 4 | 200000 (30) | (10) | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7776 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENER COMPRESSED AIR PURGE | N/A | 23 | 4 | Not reviewed in detail. No issues identified. | 4 | 200000 (30) | (10) | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7777 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 24 | 4 | Acceptable condition. No issues identified | 3a | 200000 (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYSTEM | N/A | 25 | 4 | Inoperative. Needs repair for generator assessment. | 10 | 200000 (30) | 1 | 2041 | 2010 | 2011 | No | No | 1971 |
| 1296 | 7635 | 7636 | 7767 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 26 | 4,6 | See details below. | 3a | 200000 (30) | 10 | 2041 | 2011 | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7767 | 271322 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 27 | 4,6 | Replaced in 1999 (due to difficulties in obtaining replacement parts and service) by an ABB Unitrol static excitation system which is working well. The controls and protective relays are prone to calibration drift and malfunctions, and the field flashing can maloperate. | 10 | 200000 (30) | 20 | 2041 | 2011 | 2014 | Yes | No | 1999 |
| 1296 | 7635 | 7636 | 7767 | 271322 | 99036228 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | Controls | 28 | 4,6 | Replaced in 1999 as part of exciter Controls. Review identified reported difficulties with protective relays calibration drift and malfunctions, and the field flashing maloperation. Subsequently identified as resolved by station. | 10 | 200000 (30) | (3) | 2041 | 2011 | 2014 | Yes | No | 1999 |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 29 | 4,6 | Replaced with exciter | 3a | 200000 (30) | 3 | 2041 | 2011 | 2014 | Yes | No | 1999 |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | RECTIFYING TRANSFORMER RT2 | N/A | 30 | 5,6 | Installed in 1969, the unit has a relatively high level of risk due to its age. No details on testing were identified. The unit was originally an Askarel oil filled unit but was changed in 2004 to Perchloroethylene with below 50 mg/kg PCB's. Tests in 2005 identified satisfactory results. The current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry, includes practice for the better management of PCB's in use. | 4 | (45) | 5 | 2041 | 2013 | | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7767 | 271325 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | N/A | 31 | 4,6 | Replaced with exciter. | 3a | 200000 (30) | 20 | 2041 | 2011 | 2014 | Yes | No | 1999 |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

#### 9.1.1.5 Actions

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

**TABLE 9-2 RECOMMENDED ACTIONS - 7759 #2 GENERATOR STATOR**

| Issues | Recommended Actions |
|---|---|
| 1. There is oil leaking into the stator, reducing the effectiveness of the winding support. Oil and grease has been found on the end-windings at each past inspection, and on other similar GE generators. A leak in the horizontal joint of the seal assembly was found at the last outage and a temporary repair was made – is it still effective 7 years later? | 1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 and 40 kPa (4 and 6 psi).<br>2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator<br>3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness.<br>4. Check the hydrogen consumption and seal oil consumption for leakage. |
| 2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm the condition of the core is sound, before ordering a replacement stator winding for installation in 2014, see next item). | 1. Plan for an El-cid test and a high flux test of the stator core, during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot.<br>2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. Take infra-red photos of the core and note the hot spots. (areas greater than 3 °C above the surrounding areas). |
| 3. The GE tests showed the right phase of the stator winding was in very weak condition in 2003. A rewind was recommended. An update on the winding condition should be obtained at the 2014 inspection (preferably from a second source). The tests should only be done on the winding after it has been carefully cleaned and re-tightened, and is known to be clean and dry. | 1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (Check whether the poor insulation condition was due to the high moisture or to the insulation deteriorating during the re-wedging – this is useful information for unit 3).<br>2. Also test the bushings and the PT's, and carry out ratio tests on the CT's.<br>3. Decide whether the windings will last until 2015/2020, or whether they should be replaced during the 2014 outage.<br>4. Draft a specification now, for the manufacture, test and installation of a replacement winding, together with new RTD's, and bushing and terminal plate flange seals. Also include options for new bushings and CT's, in case they are necessary. This will reduce the outage time, if a winding failure should occur during the next two years. |

| Issues | Recommended Actions |
|---|---|
| | 5. At the next major inspection, have the OEM (or potential rewind Contractors) take the stator slot and winding dimensions.<br>6. Consider taking advance delivery of the winding and store it at the plant until needed. (Make sure the new winding will fit either unit1 or unit 2, or identify why this is not possible.) |
| 4. The end-winding support structure is not able to withstand the operating and system stresses. It loosens and allows the insulation to erode and form grease. An improved end-winding support system is required. | 1. Ask the OEM for an improved end-winding support system to be supplied with the new stator winding. (Modern techniques are available to allow the supports to slide when hot, rather than develop internal stress that loosens them.)<br>2. Have the effectiveness of the new winding installation checked with the “bump” test, and additional support provided where it is found necessary |
| 5. Top ripple springs were installed to increase the time between re-wedging the stator slots. Check that the top ripple springs are still holding the slot parts of the windings firmly in place, and no loosening of the wedges/windings has occurred. | 1. Carry out a wedge tap survey, to check for loose wedges, (and find out whether unit 2 is likely to require re-wedging at its next major outage). Visually inspect the core teeth for signs of fretting dust or “grease”. |
| 6. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance. | 1. Take Doble test measurements every 2 years, during the summer outage (it is necessary to disconnect the neutral bar – make sure it is replaced carefully, and check the joint resistance with a low resistance meter (“ductor”) |
| 7. A hydrogen seal leak was found at the bushings and at the terminal plate seals. It was sealed temporarily from the inside with RTV. GE recommended the area be checked annually for leaks, but it is not known if this was done. | 1. Replace the bushing seals and the terminal plate seals. This is a difficult and expensive repair that is best done during a stator rewind. RTV sealing of the inside is satisfactory for a short time, but the deteriorated seal usually leaks elsewhere. GE uses viscaseal and a dam to identify a leak, but Hitachi repairs the leak with “titeseal” which is better. |

| A. Operation | |
|---|---|
| 1. The stator winding and core RTD's do not read credible values. They are too low. | 1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase and the hottest core RTD, on the DCS display. |
| 2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above) | 2. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary. |
| 3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results. | 1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress.<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line.<br>3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry. |
| 4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation. | 1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator. |

**TABLE 9-3 RECOMMENDED ACTIONS - 7754 #2 GENERATOR ROTOR**

| Issues | Recommended Actions |
|---|---|
| 1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 1997. (Defects have been found in other similar rotors after less than 30 years operation). | 1. Remove the retaining rings and the slot wedges.<br>2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings. |
| 2. The condition of the end-windings is not known, and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed. | 1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections. |
| 3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings. | 1. Check the insulation blocks and re-place or re-tighten as necessary. (Note the dust found probably contains asbestos). |
| 4. The ventilation system of the rotor slots uses sub-slots and radial ventilation ducts. It is prone to axial elongation (creep of the copper and restriction of the ventilation holes. | 1. Check the radial holes near the ends of the rotor body for restrictions, and record the restrictions, for future (the rotor should be re-wound when the restriction exceeds 25 % of the hole area).heck the sub-slots for oil, dirt and accumulated debris. Vacuum/blow out as much of the dirt as possible. |
| 5. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time. | 1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load.<br>2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights.<br>3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection. |

| Issues | Recommended Actions |
|---|---|
| 6. There is no record of the generator bearings being re-metalled, but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective. | 1. Re-furbish both generator bearings.<br>2. NDE the bearing Babbitt for good bond with the shell.<br>3. Check the surface for even wear,<br>4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually.<br>5. Replace if defective. Replace oil deflectors. |
| 7. GE recommended that spare bearing thermocouples be held in stock in case the installed thermocouples fail in service. | 1. The bearing thermocouples are old, and in dubious condition. New thermocouples should be installed at the next major outage. |
| 8. A week was spent working on the hydrogen seals, and numerous problems were encountered. The hydrogen seal clearances on the hydrogen side were reduced to the low end of the clearance, in an attempt to prevent oil leaking into the generator. An oil leak from the horizontal joint of the hydrogen seal was found at the CE and repaired temporarily with epoxy | 1. Replace the insulation plates of the CE seals. Check the titeseal groove at the upper and lower CE end-shield for leaks. Air-test the generator for leaks, and fix them properly at the next major inspection.<br>2. A new hydrogen seal assembly should be considered for the CE end. |
| **A. Operation** | |
| 1. The field current is not credible, it is much too low. | 1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter. |
| 2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation). | 1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or<br>2. Obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display. |
| 3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound). | 1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core. |

| Issues | Recommended Actions |
|---|---|
| 4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation). | 1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft.<br>2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or\<br>3. Install a Sohre grounding brush and shaft current and voltage monitoring system. |
| 5. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results. | 1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress.<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line.<br>3. The rotor should be kept in a clean conditions “tent” and air heaters installed to keep the windings warm and dry. |

**TABLE 9-4 7768 #2 HYDROGEN SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. Several problems were found with the float trap of the middle de-training tank of the seal oil system. The valve disc had hardened, the level control was incorrect, and the valve was installed backwards. | 1. Replace the seals, and viton disk, and gaskets, and check the operating level in the tank at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures.<br>2. GE recommends the seal oil supply piping be flushed annually, to prevent dirt in the emergency by-pass line entering the system. |
| 2. The seal oil vacuum pump is a high maintenance item. It has a rotary valve that needs to be replaced at each inspection. | 1. Purchase a spare rotary seal and install it at the next major inspection. Carry out preventive maintenance on the pump |
| 3. The hydrogen coolers were leak tested and found satisfactory, but GE recommended the gaskets be replaced at each major inspection. | 1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!) |
| 4. The liquid leak detector valve had incorrect flanges and gaskets and is | 1. Check the operation of the liquid leak detector relay, and service the parts. |

| Issues | Recommended Actions |
|---|---|
| prone to failure. | |
| 5. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater. | 1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, check for hydrogen leaks, especially at the purity meter and sampling valves. |
| 6. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve.<br>2. Locate and repair hydrogen leaks ASAP. |
| **A. Operation** | |
| 1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings. | 1. Locate and repair the hydrogen leaks.<br>2. Increase the hydrogen pressure to 207 kPa (30 psi). |
| 2. The hydrogen consumption of each generator is not recorded. | 1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded. |
| 3. The cold gas temperature is low at 30°C, GE usually recommend a minimum of 35°C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging. | 1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched.<br>2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched. |
| 4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected. | 1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating. |
| 5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve. Locate and repair hydrogen leaks ASAP. |

**TABLE 9-5 RECOMMENDED ACTIONS - 7787 #2 EXCITATION SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. The ABB static excitation system is reported to be operating satisfactorily. However, the controls and protective relays are prone to calibration drift, and malfunctions. The field flashing can maloperate | 1. Check the operation of the excitation system controls, limiters and protection relays.<br>2. Check the field breaker contacts and operation.<br>3. Check the thyristors and heat sinks, and snubbers, for signs of overheating, |
| 2. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing; the risk of generator damage is highest during initial energization on AVR control. | 1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs. |

### 9.1.1.6 Actions - Unit 2 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

**TABLE 9-6 RECOMMENDED ACTIONS – UNIT 2 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | General | 8 | 4 | Reduce operating intervals between major outages to 6 years. | 2010 | 1 |
| 1296 | 7635 | 7636 | 7753 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | General | 9 | 4 | Review generator drawings, contract information, and operating manual to clarify design details. | 2010 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Core | 10 | 4 | NDE inspection of the rotor high-stress areas should be done in 2012 - cover the retaining rings, changes in cross section of the rotor (journals and coupling etc), the rotor tooth dovetails, the slot wedges and the lead wedges for fretting fatigue cracks, the rotor core (bore sonic inspection), the bearing shells for babbitt bond, and the fans for fatigue cracks. The rotor dovetails with short steel wedges should be checked carefully, due to the higher risk of a fatigue crack developing under the high cyclic bending stress. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Core | 11 | 4 | Remove the retaining rings and the slot wedges to permit a closer inspection. Surface defects may be found in the retaining rings, a fatigue crack may exist in the dovetails, and spitting damage may be found at the wedge ends, due to negative sequence current. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Core | 12 | 4 | Install a rotor flux probe near the turbine end of the stator bore, wired out through the existing IRIS penetration and junction box, to detect the presence of shorted field turns. Usually precedes development of a rotor ground fault. The field winding has suffered extensive copper deformation and weakening of the turn insulation, and is close to the end of its useful life. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Core | 13 | 4 | Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Core | 14 | 4 | Monitor the shaft ground current or the shaft voltage at the outboard end of the generator - replace the original equipment with on-line monitoring capability. The risk of a shaft current flowing through the bearing or hydrogen seal increases during synchronous condenser operation. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Field Winding | 15 | 4 | Perform annual 500 volt megger checks on the rotor to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms). | 2010 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Field Winding | 16 | 4 | Install a field winding temperature indicator in control room. | 2010 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core | 17 | 4 | Repair hydrogen leak in the bushing box horizontal joint of the cover plate holding the bushings bushing seals. Difficult as it necessitates breaking the main connections, dropping the bushings, installing the gaskets, and re-installing the bushings. May be necessary to remove the whole bushing box. An alternative repair of poorer integrity is to seal the inside joint flanges around the bushings and terminal plates with RTV sealant. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core | 18 | 4 | Install a hydrogen consumption "totalizer" in each hydrogen supply line for dailing recording and check for leaks. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core | 19 | 4 | Maintain steady hydrogen pressure at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core | 20 | 4 | Perform, before implementing a stator rewind, a flux loop test and thermal imaging of the core to detect any hot spots and repair them before installing the new winding | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 21 | 4 | Perform a minor inspection and Doble test after 4 or 5 years, and careful monitoring of the on-line partial discharge monitoring. | 2018 | 1 |

Table 9-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 22 | 4 | Take partial discharge activity readings in the slot portion of the windings and in the end-winding portion during normal service conditions. Work with IRIS to determine a repair priority so that the results are available in time to assess replacing the windings during the 2014 outage. Detect de-lamination of the insulation tapes, deterioration in the low-resistivity paint at the outer surface (ground wall) in the slots, and discharges in the end-windings. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 23 | 4 | Repeat the DC hipot test at the next major inspection, taking extra care to ensure the insulation is dry before the test. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 24 | 4 | Perform an intermediate inspection of the stator end-windings after 4 years to establish the presence of oil and grease on the end-windings to better establish the timing of the next major inspection | 2018 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 25 | 4 | Proceed with planning work for a rewind - typically requires 9 to 12 months to plan and carry out a stator rewind, plus site work of 4-6 months. | 2012 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Winding | 26 | 4 | Evaluate proceeding with the installation of a new stator winding at the next major outage in 2014 following overhaul of Unit 1. | 2012 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | Hydrogen | 27 | 4 | Install a hydrogen consumption "totalizer" in each hydrogen supply line for daily recording and check for leaks. | 2011 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 28 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | TURB AC SEAL OIL PUMP EAST | N/A | 29 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN AC SEAL OIL PUMP WEST | N/A | 30 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN DC SEAL OIL PUMP | N/A | 31 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN SEAL OIL VACUUM PUMP | N/A | 32 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN CO2 GAS PURGE SYSTEM | N/A | 33 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENER COMPRESSED AIR PURGE | N/A | 34 | 4 | No specific recommended actions beyond normal major overhaul work. | 2014 | 2 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 35 | 4 | Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals. This will reduce the risk of a seal oil spill into the generator and will also reduce the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. A change in the bearing height and alignment of the rotor, which can increase the bearing vibration levels, will also be avoided. | 2011 | 1 |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYS | N/A | 36 | 4 | Repair and monitor results for generator condition analyses. | 2010 | 1 |
| 1296 | 7635 | 7636 | 7767 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | Static Exciter | 37 | 4,6 | Upgrade Unit 2 Static Exciter controls compatible with the latest Unitrol 6000 system. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271322 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 39 | 4,6 | No specific recommended actions, beyond normal major overhaul work. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271324 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 40 | 4,6 | Replace oil or transformer as per PCB regulations when required. No specific recommended actions beyond normal major overhaul work. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271325 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | N/A | 41 | 4,6 | No specific recommended actions beyond normal major overhaul work. | 2014 | 1 |

### 9.1.1.7 Risk Assessment

Table 9-7 below illustrates the risk assessment for the Unit 2 generator, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-7 RISK ASSESSMENT – UNIT 2 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Forging and Field Windings: | 13 | 4 | Electrical failure - EOL. | (15) | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Assess in 2014 overhaul the need for a rotor rewind by 2020+. Evaluate techno-economic values of early implementation in 2015 as part of synchronous condenser conversion. |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | Rotor Forging and Field Windings: | 14 | 4 | Mechanical failure retaining rings. | (10) | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Removal of the retaining rings and inspection in 2014. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame: | 15 | 4 | Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse). | (15) | None | 3 | C | Medium | 3 | C | High | Loss of unit generator and SC capability. Potential serious injury situation. | Extra V/f protection is desirable if the generator is energized on AVR control, as core damage occurs faster because it goes to ceiling excitation (typically 160% rated flux). It should be noted that this V/f protection may not be applicable if the generator is energized on manual control. The standard protection against over-fluxing is the volts/hertz relay. It is recommended that the V/f element of the new generator multi-functional relay be set up to provide back-up protection, especially during off-line conditions. Initial energization is the time of highest risk. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame: | 16 | 4 | Mechanical - loose plates vibrating in the magnetic field then break off and damage the stator winding, more prevalent at the core ends. | (4) | None | 3 | C | Medium | 3 | B | Medium | Loose plates break off and damage the stator winding. | Check for signs of red iron oxide dust in the stator bore as the standard sign of loose iron, and confirm by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Core and Frame: | 17 | 4 | Electrical - failures of the stator winding, and/or poor stator winding ground protection. | (10) | None | 3 | D | High | 3 | C | High | Damage to stator core. | 2014 Inspection and repairs/ stator rewind. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings: | 18 | 4 | Electrical - insulation/winding failure - most likely to occur during serious system over-voltage transients. | (4) | None | 3 | D | High | 3 | C | High | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable. | Rewind the stator in 2014. Evaluate techno-economic risk of deferral at next recommended overhaul in 2020 based on finding of Unit 1 overhaul. The generator is currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate the surges, or upon the statistical unlikelihood of the worst over-voltage situation occurring. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings: | 19 | 4 | Mechanical/electrical - can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, which have poor mechanical properties. | (4) | None | 3 | D | High | 3 | B | Medium | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable. | Rewind stator in 2014. Evaluate techno-economic risk of deferral to 2020 at next recommended overhaul. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required. |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Stator Windings: | 20 | 4 | Mechanical/electrical - an increasing risk that the end-windings will loosen again after seven years of operation after 2003 rewedging. The line-end coils and phase leads are at most risk of distortion, and could fail during a severe or a sustained system fault condition. | (4) | None | 2 | D | Medium | 2 | B | Low | The line-end coils and phase leads are at most risk of distortion and could fail during a severe or a sustained system fault condition. | Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen System Pressure Control | 21 | 4 | Mechanical/electrical/fire. | 2 | None | 3 | C | Medium | 3 | D | High | Seal Leak, Hydrogen Fire/Expl - oil leaks into the stator if the flow rate is too high, | New hydrogen seals and totalizer. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen System - Purity meter and | 22 | 4 | Electrical/fire. | 10 | None | 1 | C | Low | 1 | D | High | Hydrogen fire/explosion. | Recent replacement - monitor condition and maintain. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 23 | | Mech - loss, spill-hydrogen leak. | 10 | None | 2 | C | Low | 2 | C | Medium | Hydrogen fire. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | TURB AC SEAL OIL PUMP EAST | N/A | 24 | | Mech - loss oil seal. | 5 | None | 2 | C | Medium | 2 | C | Medium | Hydrogen fire or unit shutdown. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN AC SEAL OIL PUMP WEST | N/A | 25 | | Mech - loss oil seal. | 5 | None | 2 | C | Medium | 2 | C | Medium | Hydrogen fire or unit shutdown. | Inspect and test per current maintenance program. |

Table 9-7 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN DC SEAL OIL PUMP | N/A | 26 | | Mech - loss oil seal. | 5 | None | 2 | C | Medium | 2 | C | Medium | Hydrogen fire or unit shutdown. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN SEAL OIL VACUUM PUMP | N/A | 27 | | Mech - oil hydrogen issue. | 5 | None | 2 | C | Medium | 2 | C | Medium | Hydrogen fire or unit shutdown. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7773 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN CO2 GAS PURGE SYSTEM | N/A | 28 | | Mech - fire suppress fails. | Not reviewed | None | 1 | C | Low | 2 | C | Medium | Hydrogen fire or unit shutdown. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7777 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | Auxiliaries - Hydrogen Coolers | 30 | 4 | Electrical/fire. | 10 | None | 1 | C | Low | 1 | C | Medium | Hydrogen fire or unit shutdown. | Monitor condition and maintain. |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYS | N/A | 31 | | Measurement error. | 1 | None | 4 | D | High | 4 | A | Low | Missed generator problem. | Refurbish. |
| 1296 | 7635 | 7636 | 7767 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 32 | | See details below. | | None | | | | | | | | |
| 1296 | 7635 | 7636 | 7767 | 271322 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | Static Exciter Controls | 33 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | 2 | None | 2 | C | Medium | 2 | A | Low | Loss 1 unit generation. Damage to unit. | Upgrade controls for compatibility by 2013. |
| 1296 | 7635 | 7636 | 7767 | 271322 | 99036228 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | Static Exciter | 34 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 2 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7767 | 271322 | 99036228 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 35 | 4,6 | The static excitation system was replaced in 1999 and is reported to be working well. It should last the remaining life of the plant provided appropriate services and spare parts continue to be available. | 20 | None | 2 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 38 | 4,6, | Regulatory PCB. | 3 | 2013 PCB Reg Likely | 3 | C | Medium | 2 | B | Low | Oil spill/PCB contamination. | Replace per regulations when required. |
| 1296 | 7635 | 7636 | 7767 | 271325 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | N/A | 39 | 4,6 | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 1 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Inspect and test per current maintenance program. |

### 9.1.1.8 Life Cycle Curve and Remaining Life

Figure 9-2 and 9-3 below illustrate the life cycle curve for the Unit 2 generator. It is broken into two parts – the generator and the exciter. Differences in the scenarios identified in Section 6do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically thirty years and 200,000 to 240,000 operating hours to forty years and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode (beginning in 2015), as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and much of the hydrogen system are the same age. One vertical line illustrates the timing of the next generator overhaul in 2014. The lowest two horizontal lines represent the ranges of expected generator life for Holyrood Unit 2 based on current and historical information and expert opinion. The “Rewind Unit 2 Recommended” line is based on the recommended estimated remaining reliable stator winding life of five years at current generation levels. The other two represent longer rotor winding lives that may be achievable with decreasing reliability and higher failure risk, as well as a maximum 20 years likely for the stator and rotor cores.

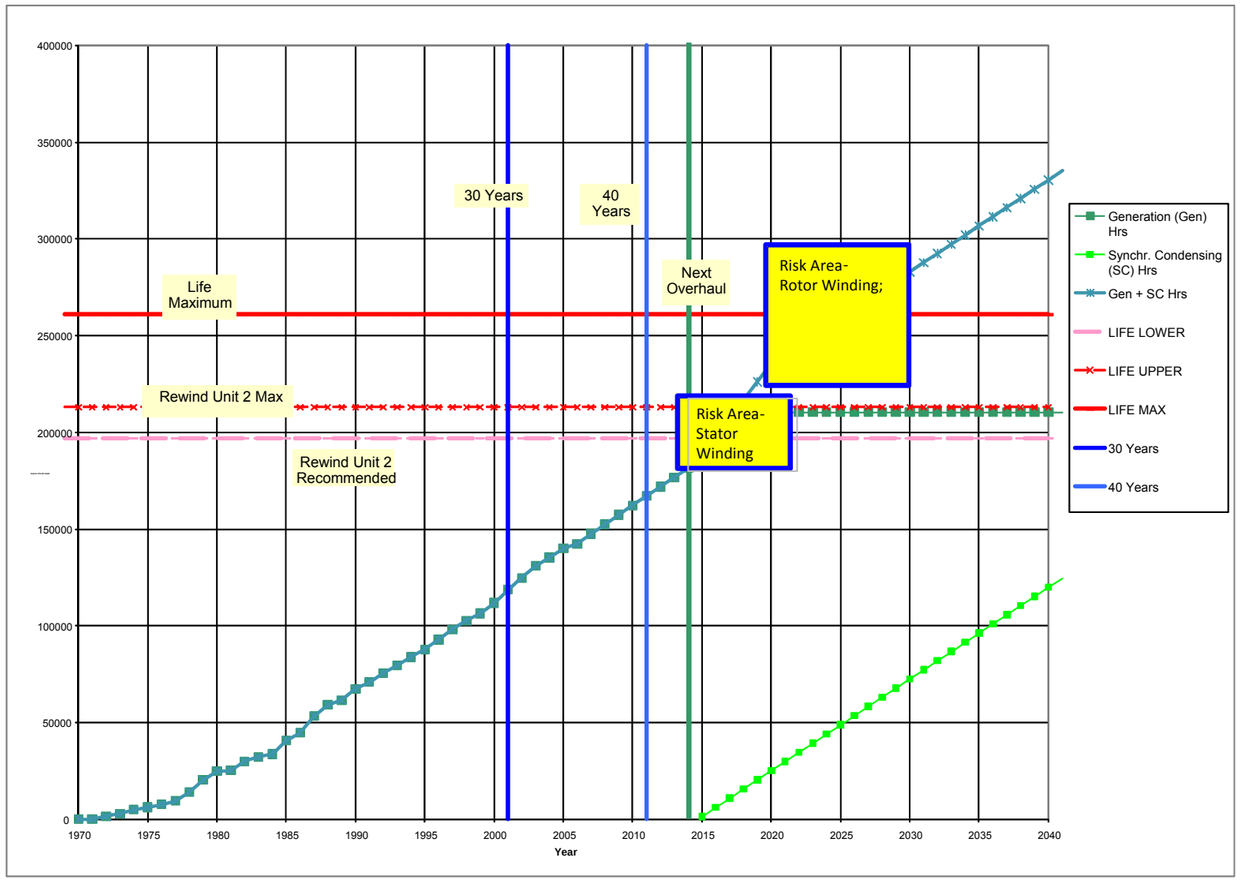



**FIGURE 9-2 LIFE CYCLE CURVE – UNIT 2 GENERATOR**

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode (beginning in 2015). It has two curves for any remaining original equipment as well as for the upgrades to the system completed in 2000.

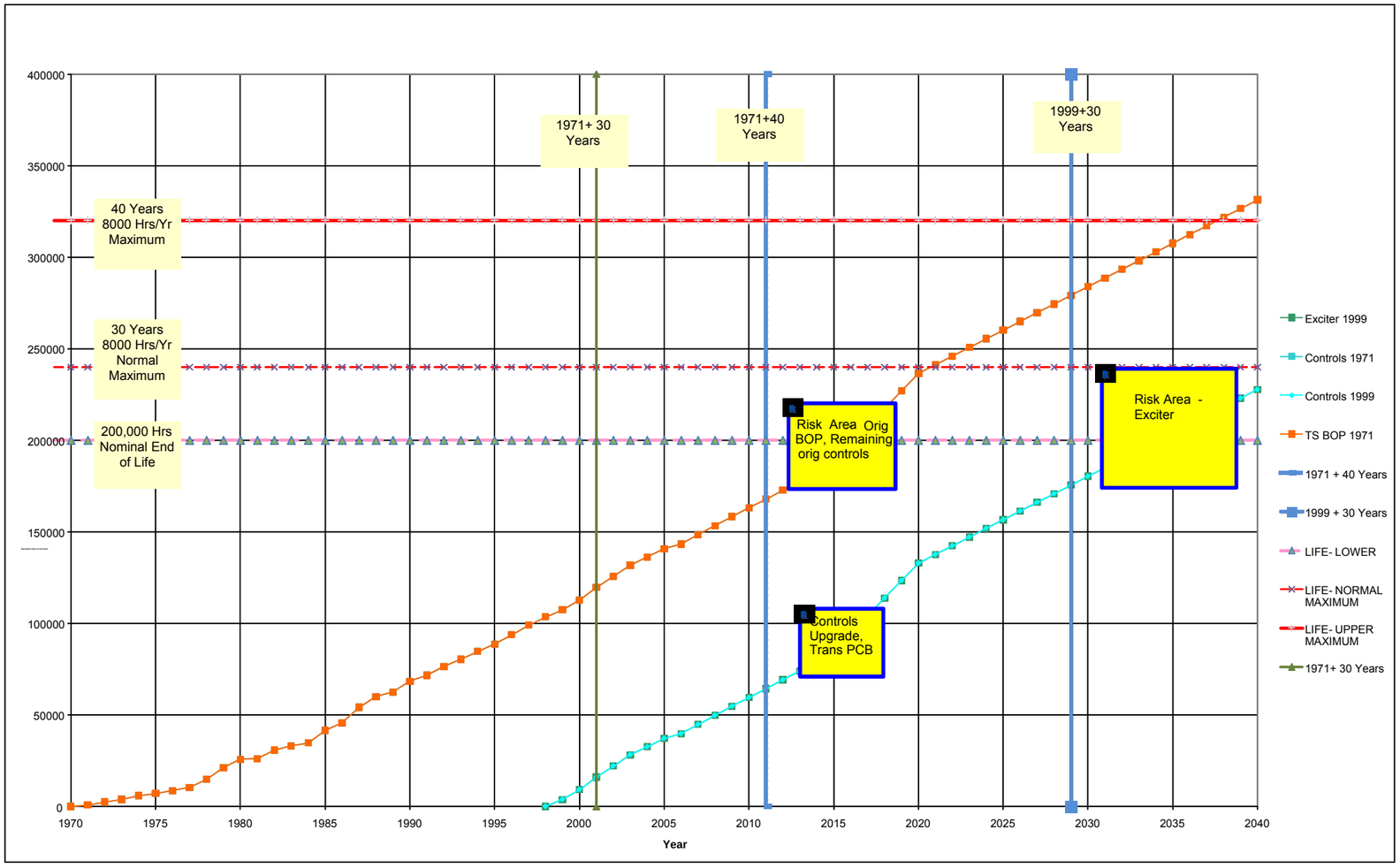



**FIGURE 9-3 LIFE CYCLE CURVE – UNIT 2 GENERATOR - EXCITER**

The curves indicate that the remaining life (RL) of the Unit 2 generator exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2041. No specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2014 overhaul to demonstrate the ability to meet the 2041 EOL date. The exciter should for the most part be able to meet an EOL of 2020, and with periodic refurbishment may meet 2041.The highlighted nearer term risk areas include the stator winding, exciter controls (upgrade only), the rectifying transformer, and some original BOP components. These systems are candidates for replacement or refurbishment – addressed in later sections. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator's life and should be a six year cycle.

#### 9.1.1.9 Level 2 Inspections – Unit 2 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by Hartford Steam Boiler Consulting, a company that was contracted by NL Hydro to review the frequency of steam turbine and generator inspections. This nine year interval between major overhauls is considered excessive, given the age and condition of the generators. A return to a six year interval is considered necessary.

**TABLE 9-8 LEVEL 2 INSPECTIONS – UNIT 2 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | None | 5 | 4 | Level 2 "Pre-Major Outage Inspection Work Allowance | 2011 | 1 | $100 |
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | None | 6 | 4 | No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes:<br>- Review generator drawings, contract information, and operating manual to clarify design details.<br>- Stator core: Core loop test and thermal image of core for hot spots before the stator is re-wound.<br>- Stator Winding: Obtain Doble test data and on-line partial discharge measurements. | 2014 | 1 | $1,961 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | None | 7 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | None | 8 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | None | 9 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | None | 10 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | TURB AC SEAL OIL PUMP EAST | None | 11 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN AC SEAL OIL PUMP WEST | None | 12 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN DC SEAL OIL PUMP | None | 13 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN SEAL OIL VACUUM PUMP | None | 14 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7773 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN CO2 GAS PURGE SYSTEM | None | 15 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7776 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENER COMPRESSED AIR PURGE | None | 16 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7777 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | None | 17 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYS | None | 18 | 4 | Repair in 2010. | | | |
| 1296 | 7635 | 7636 | 7767 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | None | 19 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7767 | 271322 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | None | 20 | 4 | No Level 2 required - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7767 | 271322 | 99036228 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | None | 21 | 4 | No Level 2 - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | None | 22 | 4 | No Level 2 - included in generator overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 7767 | 271325 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | None | 23 | 4 | No Level 2 - included in generator overhaul. | 2014 | | |

### 9.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 generator outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2014, AMEC recommends that those items that would assist in better preparing for the 2012 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2014 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

**INSPECTIONS**

**Inspections – External Components:** The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range); and
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

**Inspection – Stator Internal Components:** The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing;
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind; and
- Winding TC's – inspect and check for function.

**Inspection – Stator Core:** The following stator core items could be inspected with the stator core (rotor in) to the extent possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

**Inspection – Stator Windings:** The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism).

**Inspection – Phase Bus Connectors and Terminals:** The following could be inspected with the Stator Core (Rotor In) to the Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

**Inspection - Hydrogen Coolers:** The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

**Inspection – Rotor:** The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition(including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

**Inspection – Auxiliaries:** The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

**TESTS**

**Test – Stator:** The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
    - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
    - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

- A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
- DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen.
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

**Test – Rotor:** The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum.
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture; and
  - Shorted turns Detection
    - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise)
    - Hydrogen Seals: NDE - Megger seal insulation
    - Bearings: Megger bearing insulation.

### 9.1.1.11 Capital Projects

The following are the suggested typical capital enhancements that should be considered:

**TABLE 9-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | N/A | 12 | 4 | Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2014. | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7754 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR ROTOR | N/A | 13 | 4 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | N/A | 14 | 4 | Recommend ordering stator windings in 2013 for rewinding stator in 2014. Installation in 2014 subject to techno-economic optimization results. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | N/A | 15 | 4 | Install a hydrogen consumption “totalizer” in each hydrogen supply line. | 2011 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | N/A | 16 | 4 | Replace/overhaul seal oil skids required for SC operation. | 2015 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | TURB AC SEAL OIL PUMP EAST | N/A | 17 | 4 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN AC SEAL OIL PUMP WEST | N/A | 18 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN DC SEAL OIL PUMP | N/A | 19 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN SEAL OIL VACUUM PUMP | N/A | 20 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7773 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN CO2 GAS PURGE SYSTEM | N/A | 21 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7776 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR COMPRESSED AIR | N/A | 22 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7777 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR HYDROGEN COOLING | N/A | 23 | 4 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYS | N/A | 24 | 4 | Repair | 2010 | 1 |
| 1296 | 7635 | 7636 | 7767 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 25 | 4,6 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7767 | 271322 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 26 | 4,6 | Upgrade static exciter controls compatible with the latest Unitrol 6000 system. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 27 | 4,5 | Replace rectifying transformer. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271325 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER FIELD BREAKER | N/A | 28 | 4,6 | No capital investment required. | | |

### 9.1.2 Asset 7711 – Unit 2 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7638 #2 Turbine & Generator |
| Sub-Systems: | 7711 #2 Turbine Lubricating Oil System (7719) and Turbine Hydraulic Oil System (7741) |
| Components: | 7712 #2 Tank & Equipment<br>7715 #2 Purification<br>7720 #2 Pump South<br>7721 #2 Pump North<br>7725 #2 DC Pump<br>7743 #2 Hydraulic Oil Pump North<br>7744 #2 Hydraulic Oil Pump South |

#### 9.1.2.1 Description

The generator lube oil system is integrated into the steam turbine system. It consists of a storage system, AC and DC pumping systems, filtration, and coolers/heat exchangers. The lube oil tank holds approximately 9840 L (2600 US gallons) of Turboflo R&O 32 lubricating oil. Within the lube oil tank, there are three pumping units (two 100% AC motor driven and one 100% DC motor driven) and three 100% duty lube oil heat exchangers. The system supplies 35-45 °C oil to the turbine/generator lubrication and hydrogen seal oil systems. Pump discharge pressures at 275 – 300 kPa would be normal.

Lubricating oil heat exchanger cooling water heads can be isolated and removed for easy cleaning. An oil purifier is connected to the oil tank through a separate piping arrangement and is used primarily to remove water from the oil which accumulates because of the condensation throughout the process. The system is fitted with two 100% duty oil filters ensuring heavy particles in the oil are removed and do not reach the bearings during lubrication.

Two 100% positive displacement hydraulic oil pumps are used to operate the emergency stop valve, the combined intercept reheat stop valves, the control valves and other miscellaneous valves on the steam turbine. The pumps operate at a pressure of 15.5 MPa to counteract the large springs which normally hold the valves closed. The hydraulic oil system has its own network of high pressure piping external to the lubricating oil system which makes it somewhat easier to maintain if problems occur.

#### 9.1.2.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2014 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 158 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 188 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 212 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 212 | 120 |
| | | |
| Starts Actual - Ops to Dec 2009 | 442 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 674 | 130 |

#### 9.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in good condition and capable of meeting the requirements of the generator up to the year 2041, with regular maintenance and inspection during major generator inspections.

### 9.1.2.4 Condition Assessment

This system has been in service since Unit 2 was placed in service in 1971. Although the lubrication system is critical to the operation of the steam turbine/generator and may cause a short unit shutdown in the event of a failure, a longer shutdown may occur due to a failure of the lubricating oil piping system which cannot be inspected easily because the supply piping is installed inside of the oil returns piping which is connected to the storage tank.

The tank appears externally to be in good condition. Internal inspection reports were not available during the assessment. Failures of any of the oil pumps or the oil purifier are easily repaired and barring no hidden problems, this system should continue to operate for the time frames required. If Unit 2 is required to support synchronous condenser operation after generation mode, this system will be required to operate continuously and should not present any major issue.

All parts of the generator lube oil system are expected to be able to make their next inspection date. All are expected to require more rigorous evaluation at that time. Most will be able with maintenance and replacement to meet the generation end dates. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

**TABLE 9-10 CONDITION ASSESSMENT – UNIT 2 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 7711 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | N/A | 45 | 18 | See details below. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 46 | 18 | Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 47 | 18 | Lube oil tank appears to be in good condition. Internal inspection reports were not available. | 4 | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL PURIFICATION | N/A | 48 | 18 | Lube oil purification system is relatively new and in good condition. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 2001 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P NORT | N/A | 50 | 18 | Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P SOUT | N/A | 51 | 18 | Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 52 | 18 | Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | #2TURBINE HYDRAULIC OIL SYSTEM | N/A | 53 | 18 | In good condition based on interviews. Failures readily dealt with, backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP NORTH | N/A | 54 | 18 | In good condition based on interviews. Failures readily dealt with, backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP SOUTH | N/A | 55 | 18 | In good condition based on interviews. Failures readily dealt with, backups and replacements as required. | 3a | (30) | 10 | 2041 | 2011 | 2011 | No | No | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 lube oil system.

**TABLE 9-11 RECOMMENDED ACTIONS – UNIT 2 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | N/A | 70 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 71 | 9 | Flush the lube oil, the seal oil and the seal oil bypass lines prior to the seasonal restart of the unit every year. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 72 | 9 | Perform Level 2 inspections on oil storage tanks and internals. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL PURIFICATION | N/A | 73 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | DUPLEX FILTER FOR LUBE OIL | N/A | 74 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P NORT | N/A | 75 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P SOUT | N/A | 76 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 77 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | #2TURBINE HYDRAULIC OIL SYSTEM | N/A | 78 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP NORTH | N/A | 79 | 9 | No recommended action. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP SOUTH | N/A | 80 | 9 | No recommended action. | | |

### 9.1.2.6 Risk Assessment

Table 9-12 below illustrates the risk assessment for the Unit 2 generator lube oil system, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-12 RISK ASSESSMENT – UNIT 2 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | N/A | 51 | 9 | See details below. | 10 | None | | | | | | | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 52 | 9 | See details below. | 10 | None | | | | | | | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Tanks | 53 | 9 | Corrosion, erosion. | 10 | None | 1 | A | Low | 1 | A | Low | Oil leak – containment overflow. Safety. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Pumps & Motors | 54 | 9 | Mechanical and/or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Coolers | 55 | 9 | Mechanical failure/leaks. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Lube Oil Filters | 56 | 9 | Bearing failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL PURIFICATION | Lube Oil Filters | 57 | 9 | Mechanical and/or pluggage failure. | 10 | None | 1 | A | Low | 1 | A | Low | Water & particulate contamination. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | DUPLEX FILTER FOR LUBE OIL | N/A | 58 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P NORT | N/A | 59 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P SOUT | N/A | 60 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 61 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | #2TURBINE HYDRAULIC OIL SYSTEM | N/A | 62 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP NORTH | N/A | 63 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP SOUTH | N/A | 64 | 9 | Mechanical/electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

### 9.1.2.7 Life Cycle Curve and Remaining Life

Figure 9-4 below illustrates the life cycle curve for the Unit 2 lube oil system. Two curves are required given that the purification system was upgraded while other major elements of the lube oil system are approximately the same age. There is insufficient information to develop specific accurate curves for the storage tank, and coolers. Further detailed examination during the 2014 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing mode on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

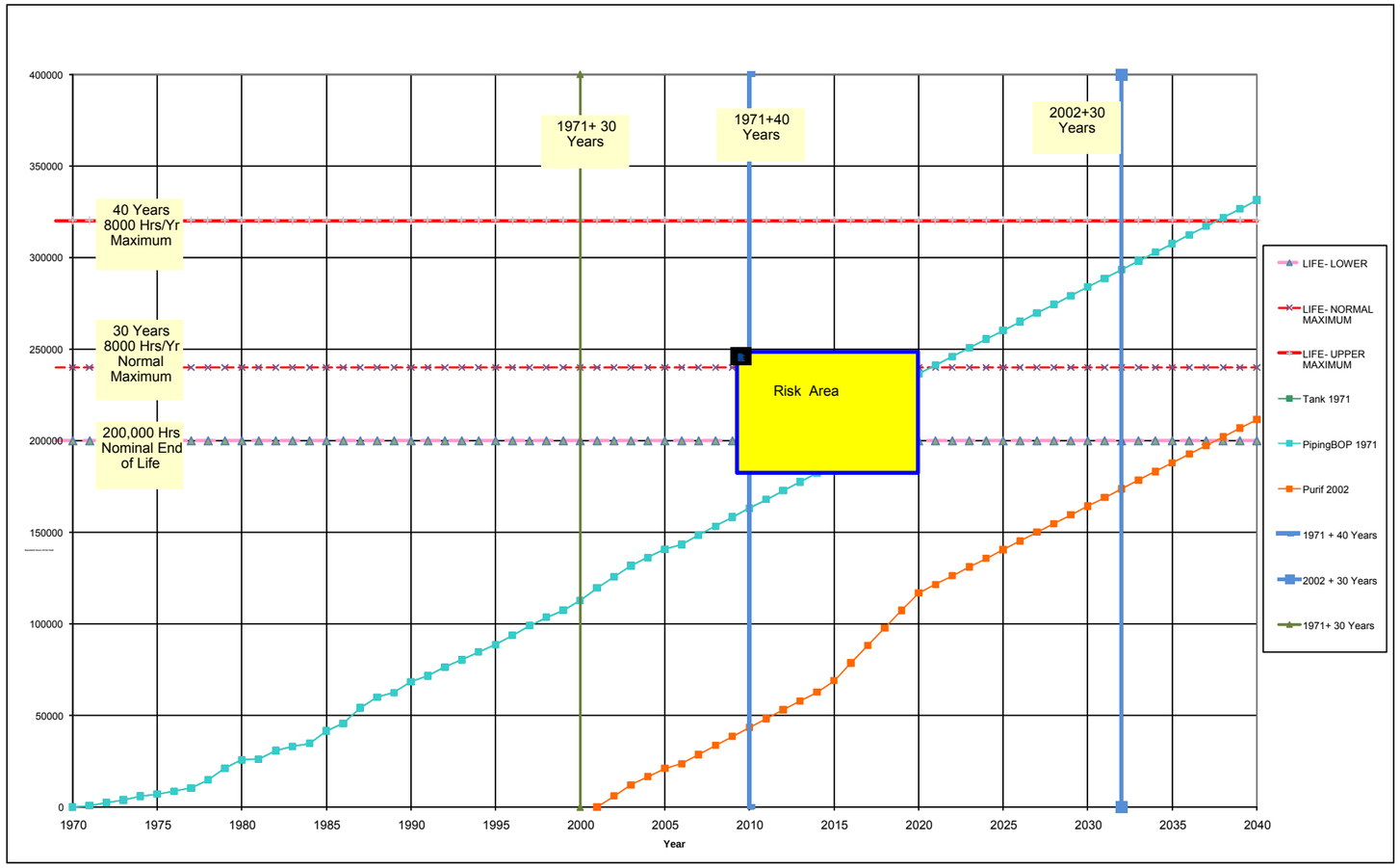



**FIGURE 9-4 LIFE CYCLE CURVE – UNIT 2 GENERATOR LUBE OIL SYSTEM**

The curves indicate that the remaining life (RL) of the Unit 2 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2041. Hence, no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2014 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2014 turbine generator overhaul. The 2014 overhaul/inspection is a fundamental element in changing the current assessment.

### 9.1.2.8 Level 2 Inspections – Unit 2 Generator Lube Oil System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-13 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-13 LEVEL 2 INSPECTIONS – UNIT 2 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 7711 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | None | 36 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE OIL SYSTEM | None | 37 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | None | 38 | 9 | NDE inspection and visual inspections of lube oil tanks and internals. | 2011 | 2 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL PURIFICATION | None | 39 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | DUPLEX FILTER FOR LUBE OIL | None | 40 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P NORT | None | 41 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P SOUT | None | 42 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | None | 43 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | #2TURBINE HYDRAULIC OIL SYSTEM | None | 44 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP NORTH | None | 45 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP SOUTH | None | 46 | 9 | No Level 2 required - included in steam turbine overhaul. | 2014 | | |

### 9.1.2.9 Capital Projects

The suggested typical capital enhancements include:

**TABLE 9-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 7711 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | N/A | 44 | 9 | Provide concrete curbing around turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 45 | 9 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 46 | 9 | Replace turbine lube oil conditioners. | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL PURIFICATION | N/A | 47 | 9 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | DUPLEX FILTER FOR LUBE OIL | N/A | 48 | 9 | Provide mechanical level switches in full flow lube oil filter compartment to detect leaks. | 2013 | 2 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P NORT | N/A | 49 | 9 | Provide electrical control (both “On” and “Off”) for the lube oil pumps in parallel with the local controls in the Control Room | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE A.C. OIL P/P SOUT | N/A | 50 | 9 | Provide electrical control (both “On” and “Off”) for the lube oil pumps in parallel with the local controls in the Control Room | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 51 | 9 | Provide paralleled electrical control for the DC Lube Oil Pump and “On” and “Off” control for all lube oil pumps in parallel with the local controls in the Control Room. | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | #2TURBINE HYDRAULIC OIL | N/A | 52 | 9 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP NORTH | N/A | 53 | 9 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7741 | 2 | #2 TURBINE | TURBINE | TURBINE HYD. OIL PUMP SOUTH | N/A | 54 | 9 | No capital investment required. | | |

### 9.1.3 Asset 8152 – Unit 2 Electrical and Control Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the electrical and control systems associated with Unit 2 are as follows:

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 8152 #2 Electrical System & Controls |
| Sub-Systems: | 8152 #2 Electrical System & Controls |
| Components: | 8138 #2 Relay Room Protection & Control<br>8144 #2 Main Controls<br>8153 #2 Generator Bus-Duct and Connections<br>8173 #2 Battery Chargers<br>8174 #2 UPS2 Inverter<br>8186 #2 Battery Banks<br>271478 #2 Switchgear 4160V/600V<br>8162 Power Centre “B” UAB2, (600V)<br>271479 #2 Turbine Supervisory System<br>299451 #2 DCS<br>COMMON SYSTEMS<br>270297 Control Cables<br>270298 Power Cables<br>600 V Metric Plugs |

#### 9.1.3.1 Description

**Asset 8138 Unit 2 Relay Room Protection & Control**

Generator G2, Transformer T2 and Auxiliaries P&C Panels, were manufactured by Canadian General Electric, and installed in 1969.

**Generator 2 and Transformer T2 Protection Panels:** These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show annunciation and T2/UST2 gas and winding temperature trips and indications.

**Unit 2 Protection Auxiliary Panel:** This panel shows DC buses indications and blocking switches.

**Unit 2 Metering Pane:** This panel shows Generator 2 and Static Exciter 2 WHR's, runtime, flexitests and stator ground fault protection that was added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

The rear of the panels show the original GE and Brown Boveri Control relays, Agastat timers and transducers.

**Asset 8144 Unit 2 Main Controls**

The original Unit 2 main controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments and Panalarm annunciation. Modifications have been made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation. In addition, a newly commissioned auto-synchronizing system has been added for automatically synchronizing Unit 2 to the Island Grid via the GE Speedtronic Mark V turbine control system. This allows the operator to select the U2 breaker and activate the Mark V synch. control, which incorporates a 25C synch. check function to permit placement of U2 on the grid.

G2, MW, Amps, MVA's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Screens and keyboards are provided to include control, indications, and annunciation of unit functions.

Original controls, located in the console desk include the following. Circulating pumps, cooling water pumps and valves, thermo probe, AC and DC oil pumps, extraction and hydraulic pumps, Vacuum pumps, speed load and load limit, AVR set-point and selection, Unit 2 trip and raise/lower volts and Unit 2 Turbine Trip pushbutton.

The original manually operated switches and indications remain for synchronizing and operation of breakers B2B11 and B2L42. See auto synch modifications above.

Original common analog instruments, for Unit 1 and Unit 2, (Stage 1), indicate incoming and running volts, incoming and running frequencies, and synchronizing.

Unit 2 relaying and transducers are situated in the Unit 2 logic cubicles behind unit 2 control room. Relays are Struthers & Dunne with Agastat timers.

**Asset 8153 Unit 2 Generator Bus-Duct and Connections**

The generator bus-duct is a 3 phase, Isolated Phase Bus, complete with PT's and Neutral Cubicle, manufactured by ITE and installed in 1969.

Bus-duct connections were modified when T1 power transformer was up-graded.

**Asset 8173 Unit 2 Battery Chargers**

(Note: Units 1/2 129VDC Battery Chargers are covered under asset 6728).

Unit 2 258VDC Battery Charger was manufactured by CIGENTEC Inc. and installed in 2001. Charger 1 is a type C3-250-200PAF3BHRGCUOD3S2X9, 600V Input, 258VDC Output, with a 200A rated maximum charger output.

Reference Holyrood Plant Charger Database. Last equipment check 04 Feb 2010.

Other information:

Unit 2 258VDC Panel was manufactured by Westinghouse, installed in 1969, and is a type CDP, complete with Westinghouse breakers.

**Asset 8174 Unit 2 UPS2 Inverter**

Inverter UPS2 was manufactured by Eaton Powerware, Series 9315 and installed in 1998. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS2 Inverter, via Distribution Splitter are as follows:

Unit 2 UPS Panel No.2 at Col L10, El 24'-2", fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, 100A main breaker, branch breakers type BQ, and was installed in 1998.

Unit 2 WDPF Panel, DP-2 relay room, fed via 125A fused disconnect, Siemens, Type NLAB, 3 phase, 4W, 225A, 42 circuit, 100A main breaker, branch breakers type BQ, and was installed in 1998.

**Asset 8186 #2 Battery Banks**

Unit 2, 129VDC Battery Bank, manufactured by C&D Technologies Inc. and installed July, 2006. Battery Bank is a Model KCR 11 and is Flooded Lead-calcium.

Reference Holyrood Plant Battery Bank Database for details. Replacement date 2031. Last equipment maintenance check was 04 Feb.2010.

Unit 2, 258VDC Battery Bank. Manufacturer: C&D Technologies Inc. and installed June 1998. Battery Bank is a Model KCR 11 and is Flooded Lead-calcium.

Reference Holyrood Plant Battery Bank Database for details. Replacement date 2023. Last equipment maintenance check was 04 Feb. 2010.

**Asset 271478 Unit 2 Switchgear 4160V/600V**

Unit Board UB2 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear, utilizes original draw-out power breakers, Type 5HK, 1200A and 2000A. All protection, synch, and control relays are original CGE electro-mechanical. Schweitzer 701, Motor Protection Relays have been added to some feeders. All other loads utilize original P&B Golds' relays.

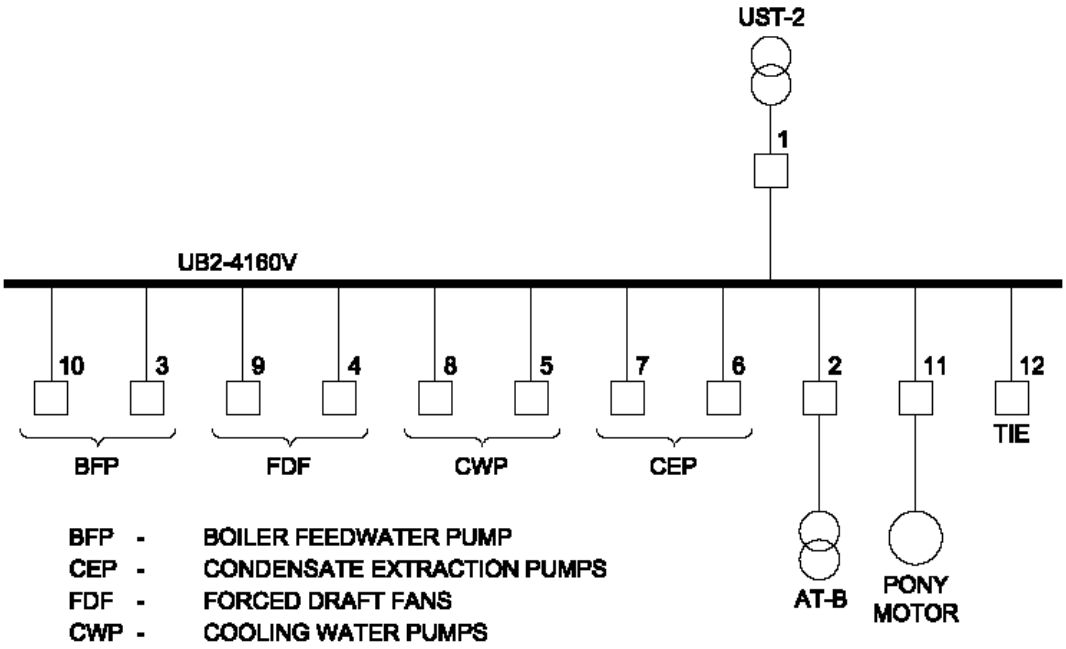



FIGURE 9-5 UB2 SWITCHGEAR

**Asset 8162 Power Centre "B" UAB2, (600V), manufactured by CGE and installed in 1968.**

The switchboard utilizes CGE AK-50 Incoming / Tie Breakers, and CGE AK-25 Feeder breakers.

The Unit Aux. Transformer AT-B is a Delta, type EV1. 1500kVA, 4160V:600/347V, AN, complete with primary tap-changer, +2@2.5%, -2@2.55, and was installed in 2000. The original transformer faulted.

**Asset 271479 Unit 2 Turbine Supervisory System**

The Turbine Supervisory System was manufactured by Bently Nevada and installed in 1990. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

Functionality of the Bently Nevada system has been partially transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevada, and is transferred via a DDX link to the instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 2 mechanical protection.

The system is operating well, with numerous spares available at the plant, and some "boards" that might be repaired to possibly extend the system life indefinitely.

As of July 01, 2009, GE commenced the transition of the 3300 System from a Phase 2 status (Mature product) to a Phase 3 status (Spares only). This means that the product is no longer available for new installations, and that no new customer modifications are available. During Phase 3, new and some existing spares are available, as is repair and support. However, GE are suggesting that Phase 3 status will continue for approximately 12 months, i.e. until July, 2010, at which time they will move to Phase 4, (No Spares, Limited Support). Therefore, as of July, 2010 the system will progress at a Phase 4 status toward Phase 5 (Obsolescence), which will come into being at some future indeterminate time.

**Asset 299451 Unit 2, DCS**

The DCS, manufactured by Foxboro, is an Invensys system and was installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was installed at that time. Original system was hard-wired, but later updated to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004. The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2;
- IACC, Version 2.3.1 (Configuration Program); and
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program).

Reference Foxboro Drawing D545390-SA-001 for system configuration.

### 9.1.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Replaced (DCS) | 2002-2003 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2014 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 158 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 188 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 212 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 212 | 120 |
| Starts Actual - Ops to Dec 2009 | 442 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 674 | 130 |

### 9.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 9.1.3.1 Description and in 9.1.3.4 Condition Assessment.

### 9.1.3.4 Condition Assessment

Where a system is fully or partially required for synchronous condensing or there is uncertainty, it is included here. The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined approximately on a 5 year frequency. The areas of most concern are the exciter controls and protection and motor controls – which have in fact been identified by the plant as an area in need of upgrade in the very short term. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring need replacement or refurbishing. The condition assessment for the various systems is presented in the following table.

**TABLE 9-15 CONDITION ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | N/A | 155 | 6 | | | | | | | | | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 156 | 6 | Generator, Transformer and Auxiliary Protection and Metering Panels tests in 2006 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2012, 2018, 2024, etc.) | 10 | (30) | 10 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 157 | 6 | Breaker overhauls were been carried out in 2006 and 2007, except UB2-2 in 1996 (See Appendix). All 4160V switchgear is applied within ratings. Past normal life - extended by overhauls/maintenance. | 10 | (25) | 5 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 158 | 6 | There are age and spares problems with the relaying system. | 4 | (30) | 10 | 2041 | | | Yes | No | 1971 |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DCS | DCS | N/A | 159 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 10+ | 2041 | | | Yes | No | 2004 |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | N/A | 160 | 6 | A partial maintenance inspection in May 2009 using a 5kV Meggar indicated good insulation test readings. No testing was indicated of Section 1 (A - toward generator and B - toward main transformer). | 4 | 200000 (30) | (10) | 2041 | | | Yes | No | 1969 |
| 1296 | 7635 | 8152 | 8156 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 162 | 6 | See details below. | 3a | (25) | 10 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 8156 | 8157 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-2 | N/A | 163 | 6 | 2006 tests were satisfactory. Some ingress of dust and foreign material. | 3a | (30) | 10 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | N/A | 167 | 6 | Last PM performed between 1992 and 1997 when breakers sent to external company for maintenance and protection relay replacement. All 600V switchgear is applied within their ratings. | 3a | (25) | (10) | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 8156 | 8168 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC B1 | N/A | 168 | 6 | MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceed the rating of the short circuit protection devices within the individual wrappers. | 4 | (25) | 3 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 8173 | 99032478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGER | N/A | 169 | 6 | Installed in 2001. Last equipment check 04 Feb 2010. Good condition. | 3a | (20) | 15 | 2041 | | | No | No | 2001 |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | N/A | 170 | 6 | New in 1998. Batteries changed at 7 years and tested every 4 weeks. Maintenance performed 04 Feb 2010. | 10 | (25) | 10 | 2041 | | | No | No | 1998 |
| 1296 | 7635 | 8152 | 8186 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | BATTERY BANKS | N/A | 171 | 6 | Installed 2006. Replacement date 2031. Last equipment maintenance check was 04 Feb 2010. | 3a | (25) | 20 | 2041 | | | Yes | No | 2006 |
| 1296 | 7635 | 8152 | 8186 | 99032477 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT BATTERY BANK | N/A | 172 | 6 | Installed 1998. Replacement date 2023. Last equipment maintenance check was 04 Feb 2010. | 3a | (25) | 15 | 2041 | | | No | No | 1998 |
| 1296 | 7635 | 8152 | 8186 | 99032479 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT DC BATTERY CHARGER | N/A | 173 | 6 | New in 2001. | 3a | (25) | 15 | 2041 | | | No | No | 2001 |
| 1296 | 7635 | 8152 | 271475 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 174 | 6 | Normal inspections and PM scheduled every 10 years - has not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power, and control are "thrown" into trays that have been convenient in the routings associated with the new installations. | 3a | (50) | (30) | 2041 | 1995 | | No | No | 1971 |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | N/A | 175 | 6 | Original equipment. No recent testing. | 4 | (50) | (10) | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | N/A | 176 | 6 | Original equipment. No recent testing. | 4 | (50) | (10) | 2041 | | | No | No | 1971 |

Notes:

1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.1.3.5 Actions – Unit 2 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Based on the condition assessment, the following actions are recommended for the electrical and control systems.

**TABLE 9-16 RECOMMENDED ACTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 8138 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 212 | 6 | Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc. | 2011 | 1 |
| 1296 | 7635 | 8152 | 8138 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 213 | 6 | Test Station Service Transformers UT1 and UT2 Protection Panels - next tests planned for 2012, 2018, 2024, etc. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8138 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 214 | 6 | Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015 to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Switchgear 4160V/600V | 215 | 6 | Include this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2011 | 2 |
| 1296 | 7635 | 8152 | 271478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Switchgear 4160V/600V | 216 | 6 | Overhaul all 4160V switchgear breakers. With the availability of spare breaker elements, consider a program to overhaul breakers 3,4,5,6,7,8,9,10, off site if necessary. With essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2012 | 2 |
| 1296 | 7635 | 8152 | 271478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Switchgear 4160V/600V | 217 | 6 | During the complete overhaul, replace existing breakers 1, 2 and 12 with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Spare cubicle (UB2-12) can be used for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50 ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs. | 2014 | 1 |
| 1296 | 7635 | 8152 | 8144 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | Main Controls | 218 | 6 | Assess removing existing Main Controls control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2011 | 2 |
| 1296 | 7635 | 8152 | 299451 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | DCS | 219 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 7635 | 8152 | 8153 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | Generator Bus-Duct and Connections | 220 | 6 | Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows:<br>1. Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>2. Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct. | 2011 | 1 |
| 1296 | 7635 | 8152 | 8155 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. TRANSFORMER & AUX'S | GEN. TRANSFORMER & AUX'S | N/A | 221 | 6 | No recommended actions. | | |
| 1296 | 7635 | 8152 | 8156 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 222 | 6 | No recommended actions. | | |
| 1296 | 7635 | 8152 | 8156 | 8157 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-2 | N/A | 223 | 6 | No recommended actions. | | |
| 1296 | 7635 | 8152 | 8156 | 8162 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Power Centre "B" UAB2, (600V), | 224 | 6 | Change all Power Centre "B" UAB2, (600V) protection setting to improve arc-flash ratings, unless already completed, including:<br>1. Protection settings adjustment on breaker B1, secondary of transformer AT-B<br>2. Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder. | 2011 | 1 |
| 1296 | 7635 | 8152 | 8156 | 8162 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Power Centre "B" UAB2, (600V), | 225 | 6 | Inspect and test transformer AT-B and the individual AK-50 / AK-25 air circuit breakers, and check the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and retorqued. | 2011 | 1 |

Table 9-16 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 8156 | 8162 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Power Centre "B" UAB2, (600V), | 226 | 6 | Overhaul to an "as new condition" or replace the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program to be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8156 | 8168 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC B1 | N/A | 227 | 6 | Replace of refurbish as required given fault current exceedances. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8173 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 230 | 6 | Continue planned maintenance on newer units. | 2011 | 2 |
| 1296 | 7635 | 8152 | 8173 | 99032476 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 232 | 6 | No recommended actions. | | |
| 1296 | 7635 | 8152 | 8173 | 99032478 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGER | Battery Chargers | 233 | 6 | Replace Unit 2 Battery Chargers 258VDC Panel and breakers. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8174 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | Inverter UPS2 | 234 | 6 | Overhaul/upgrade unit to extend the life expectancy to at least 2020 | 2012 | 1 |
| 1296 | 7635 | 8152 | 8174 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | Inverter UPS2 | 235 | 6 | Optimize in conjunction with UPS1, UPS3 and UPS4 the possible replacement of the four units with two parallel units for requirement for inverters from 2020 to 2041. | 2011 | 2 |
| 1296 | 7635 | 8152 | 8186 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | BATTERY BANKS | Battery Banks | 236 | 6 | No action is required. | | |
| 1296 | 7635 | 8152 | 8186 | 99032477 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT BATTERY BANK | N/A | 237 | 6 | No action is required. | | |
| 1296 | 7635 | 8152 | 8186 | 99032479 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT DC BATTERY CHARGER | N/A | 238 | 6 | No action is required. | | |
| 1296 | 7635 | 8152 | 271475 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 239 | 6 | Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out. | 2011 | 3 |
| 1296 | 7635 | 8152 | 271476 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | N/A | 240 | 6 | Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. | 2011 | 3 |
| 1296 | 7635 | 8152 | 271477 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | N/A | 241 | 6 | Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable. | 2011 | 3 |

### 9.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. Table 9-17 below illustrates the risk assessment for the Unit 2 electrical and control systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-17 RISK ASSESSMENT UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 189 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 190 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 191 | 6 | Electrical fault, mechanical fatigue ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 192 | 6 | Electrical fault, ops error. | 10+ | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Maintain. |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | N/A | 193 | 6 | Electrical fault. | (10) | None | 3 | C-D | Medium/ High | 3 | C-D | High | Loss 1 unit generation. Damage to unit. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 8155 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. TRANSFORMER & AUXS | GEN. TRANSFORMER & AUXS | N/A | 194 | | Regulatory PCB. | 3 | 2013 PCB Reg likely. | 3 | C | Medium | 2 | B | Low | Oil spill/PCB contamination. | Replace per regulations when required. |
| 1296 | 7635 | 8152 | 8156 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 195 | | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 1 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Inspect and test per current maintenance program. |
| 1296 | 7635 | 8152 | 8156 | 8157 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-2 | N/A | 196 | | See details below. | 5 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Power Centre (600V) | 197 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8156 | 8168 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC B1 | N/A | 198 | | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8173 | 99032476 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 203 | | Electrical or chemical fault. | 20 | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 8173 | 99032478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGER | N/A | 204 | | Electrical or chemical fault. | 15 | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | N/A | 205 | 6 | Electrical fault. | 10 | None | 3,1 | B | Medium/Low | 1 | B | Low | Unit damage on fail to safe shutdown. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8186 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | BATTERY BANKS | N/A | 206 | | Electrical or chemical fault. | 20 | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 8186 | 99032477 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT BATTERY BANK | N/A | 207 | | Electrical or chemical fault. | 15 | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 8186 | 99032479 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT DC BATTERY CHARGER | N/A | 208 | | Electrical or chemical fault. | 15 | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 271475 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 209 | | Electrical fault. | (30) | None | 1 | C | Low | 1 | B | Low | Loss up to 1 unit generation. Damage to equipment. | Clean and re-organize. |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | N/A | 210 | 6 | Electrical fault. | (10) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage. | Test indicative number. |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | N/A | 211 | 6 | Electrical fault. | (10) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage. | Test indicative number. |

### 9.1.3.7 Life Cycle Curve and Remaining Life

Figures 9-6 and 9-7 below illustrate the life cycle curve for the Unit 2 electrical and control systems associated with generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

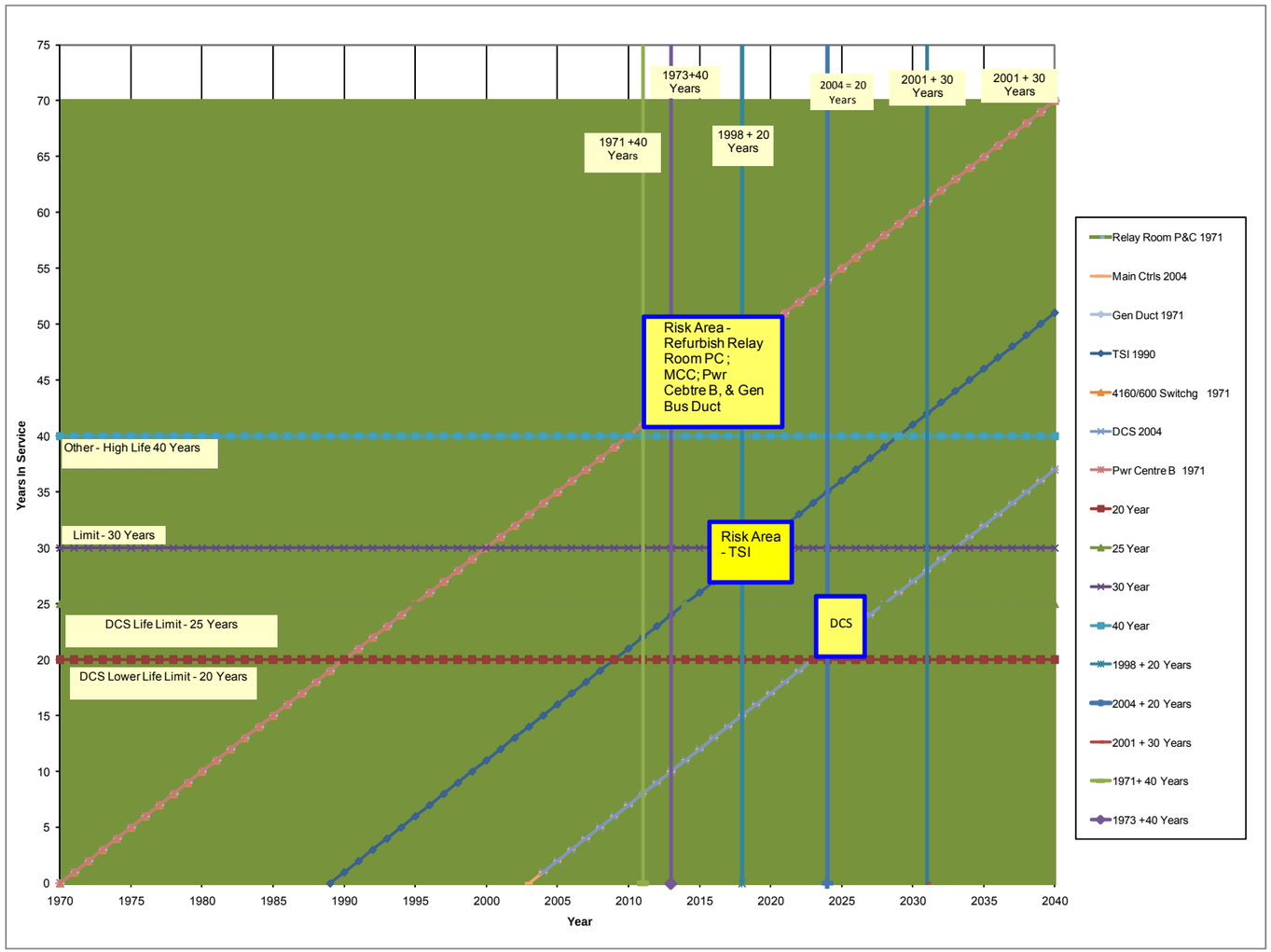



**FIGURE 9-6 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)**

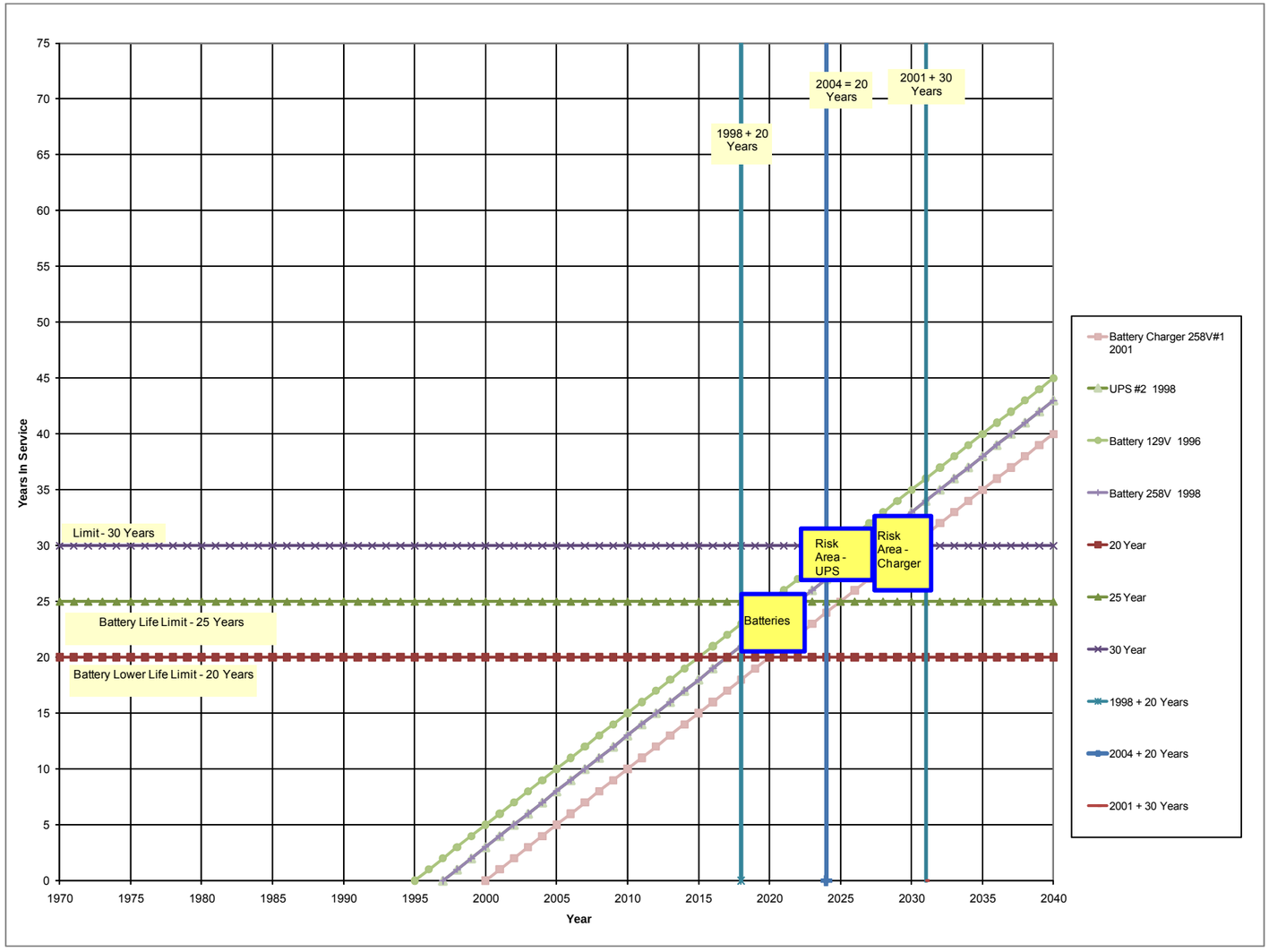



**FIGURE 9-7 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)**

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that most of the rest of the equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

### 9.1.3.8 Level 2 Inspections – Unit 2 Electrical and Control Systems Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the Table 9-18.

**TABLE 9-18 LEVEL 2 INSPECTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | None | 154 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | None | 155 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | None | 156 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | None | 157 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DCS | DCS | None | 158 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | Generator Bus-Duct and Connections | 159 | 6 | Conduct complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct:<br>- Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check that resistance values are below the manufacturer's recommended maximum value.<br>- Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft of bus-duct. | 2011 | 1 | $15 |
| 1296 | 7635 | 8152 | 8155 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. TRANSFORMER & AUXS | GEN. TRANSFORMER & AUXS | None | 160 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8156 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | None | 161 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8156 | 8157 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-2 | None | 162 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Power Centre "B" UAB2, (600 | 163 | 6 | Inspection and testing of transformer AT-B and the individual AK-50 / AK-25 air circuit breakers and check the bussing. If the plant three year thermal scan program has not included this equipment then bus-bar bolts should be checked and retorqued. Inspection and testing of the transformer should include turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. | | | |
| 1296 | 7635 | 8152 | 8156 | 8168 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC B1 | None | 164 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8173 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | BATTERY CHARGERS | None | 165 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8173 | 99032476 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | None | 167 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8173 | 99032478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGER | None | 168 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | None | 169 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8186 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | BATTERY BANKS | None | 170 | 6 | No Level 2 required. | | | |

Table 9-18 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 8186 | 99032477 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT BATTERY BANK | None | 171 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8186 | 99032479 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT DC BATTERY CHARGER | None | 172 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 271475 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 173 | 6 | No Level 2 required. | | 3 | |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 174 | 6 | Inspection and test selected control cables (especially if the cables are required to be re-run to different equipment):<br>- Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. | 2011 | 3 | $7 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 175 | 6 | Inspection and test selected power (4160V, 600V) cables (especially if the cables are required to be re-run to different equipment):<br>- Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. Check the resistance values are below the manufacturer's recommended maximum value.<br>- Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft of cable. | 2011 | 3 | $10 |

### 9.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

**TABLE 9-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | N/A | 148 | | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 149 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 150 | 6 | Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 151 | 6 | Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 3,4,5,6,7,8,9,10 off site if necessary. There will be little interruption to plant requirements, recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 152 | 6 | Replace existing breakers 1, 2 and 12 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB2-12) for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breakers that might be used. One RPR2 would service U1 and U2 needs. | 2013 | 1 |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 153 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DCS | DCS | N/A | 154 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | N/A | 155 | 6 | None planned, but may result from tests | | |
| 1296 | 7635 | 8152 | 8155 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. TRANSFORMER & AUX'S | GEN. TRANSFORMER & AUX'S | N/A | 156 | | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8156 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 157 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8156 | 8157 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-2 | N/A | 158 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | N/A | 159 | 6 | Change all protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker B1, secondary of transformer AT-B.<br>- Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder. | 2011 | 1 |

Table 9-19 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | N/A | 160 | 6 | Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2013 | 1 |
| 1296 | 7635 | 8152 | 8156 | 8168 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | TURBINE & BOILER AREA MCC B! | N/A | 161 | 6 | Replace as required per current inspection and overhaul findings. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8173 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 162 | 6 | Replace Unit 2 Battery Chargers 258VDC Panel and breakers | 2013 | 1 |
| 1296 | 7635 | 8152 | 8173 | 99032476 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | N/A | 164 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8173 | 99032478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGER | N/A | 167 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | N/A | 168 | 6 | Overhaul/upgrade unit to extend the life expectancy to at least 2020. | 2012 | 1 |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | N/A | 169 | 6 | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement. | 2012 | 2 |
| 1296 | 7635 | 8152 | 8186 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | BATTERY BANKS | N/A | 170 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8186 | 99032477 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT BATTERY BANK | N/A | 171 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8186 | 99032479 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY BANKS | 250 VOLT DC BATTERY CHARGER | N/A | 172 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 271475 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 173 | 6 | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | N/A | 174 | 6 | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | N/A | 175 | 6 | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |

### 9.1.4 Asset 271486 – Unit 2 Cooling Water Systems Associated with Generation

(Detailed Technical Assessment in Working Papers, Appendices 11, 8)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8093 #2 Unit Generation Services |
| Sub-Systems: | 271486 #2 CW System |
| Components: | 8097 #2 CW Travelling Screens East |
| | 8098 #2 CW Travelling Screens West |
| | 8106 #2 CW Pump East |
| | 8107 #2 CW Pump West |
| | 8095 #2 CW Intake |
| | 8120 #2 CW Discharge to Outfall |
| | 8132 #2 General Service Water |
| | 7703 #2 Turbine Generator Cooling Water |

#### 9.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouses sea water intakes, traveling screens, and general service water system;
- Sea water heat exchanger system;
- Seawater discharge system; and
- Electrical and control requirements.

**Circulating Water (CW) Pump & Screens Systems:** Circulating water (CW) systems servicing Unit 2 consists of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

**Turbine Generator (TG) Auxiliary Cooling Water System:** Sea water cooling is required for the TG auxiliary cooling water system required for synchronous condensing operation. Unit 3 is currently supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump pit), from the water take-off from the Stage 2 pumphouse cooling water pumps, and from an interconnection with the Units 1

and 2 cooling water system. Typically, when only Unit 3 is running as synchronous condenser, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For the purpose of long term synchronous condensing operation to 2041 for all three units, the intent is to supply seawater from a small, permanent pump arrangement similar to Unit 3 as shown in Section 8.1.4.1. It may come from one pumphouse or in the form of two separate, but interconnected systems.



**FIGURE 9-8 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING GT AUXILIARY COOLING WATER**

### 9.1.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Overhaul/Inspection | Not identified |
| Next Major Overhaul/Inspection | Not Identified |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | **Generation (Gen)** | **Synchronous Condensing (SC)** |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 158 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 188 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 212 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 212 | 120 |
| Starts Actual - Ops to Dec 2009 | 442 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 674 | 130 |

### 9.1.4.3 Inspection and Repair History

**CW Travelling Screens:** Travelling screen internals have been replaced on Unit 2 in last 5 to 10 years. Interviews suggest that no recent issues have been experienced with this unit. Visual examination confirms that the Unit 2 screens generally appear to be in good shape.

The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

**CW Wash Water Pumps and Motors:** An external inspection of the pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**CW Pumps:** CW pumps on all units are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle as indicated in Table 9-20 below.

**TABLE 9-20 SCHEDULED MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for synchronous condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary.

**CW Pump Motors:** In accordance with the plant PM process, motors are tested electrically every year..

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves and fittings from the CW pump discharge to the inlet of the 162 cm (64 inch) concrete piping that is installed underground to the Unit 2 condensers has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly a complete replacement.

**Cooling Water System Intake & Discharge:** The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that is installed underground to the unit condensers has periodically been pumped, dewatered, and inspected by plant staff. No specific corrosion, spalling, cracks or fractures were identified and no patching of the system has been done. There have been no obvious issues with the systems, but no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle as per the schedule below shown in Table 9-21.

**TABLE 9-21 PM INSPECTIONS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 9.1.4.4 Condition Assessment

The condition assessment of the Unit 2 cooling water systems associated with generators is illustrated below in Table 9-22:

**TABLE 9-22 CONDITION ASSESSMENT – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 131 | 12 | Piping, pumps, and heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available. | 4 | 200000 (30) | 10 | 2041 | 2011 | | No | No | 1971 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Sea water piping | 132 | 11,15 | Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid. | 4 | (30) | (10) | 2041 | 2011 | | No | No | 1971 |
| 1296 | 7635 | 8093 | 7703 | 9622 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP SOUTH | N/A | 133 | 11,15 | Relatively new AC pumps and motors (no date available). No issue with them. | 4 | (30) | (10) | 2041 | 2012 | | No | No | 2000 |
| 1296 | 7635 | 8093 | 7703 | 9624 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP NORTH | N/A | 134 | 11,15 | Relatively new AC pumps and motors (no date available). No issue with them. | 4 | (30) | (10) | 2041 | 2012 | | No | No | 2000 |
| 1296 | 7635 | 8093 | 7703 | 299550 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING STRUCTURE | N/A | 135 | 11,15 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | 10 | 2041 | | | No | No | 2000 |
| 1296 | 7635 | 8093 | 7703 | 299551 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING STRUCTURE | N/A | 136 | 11,15 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | 10 | 2041 | | | No | No | 2000 |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 137 | 11,15 | PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected | 4 | (50) | 10 | 2041 | | | Yes | No | 1990 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 147 | 11 | Generally in good condition, however significant corrosion on major steel pipes, pumps, and valves. | 4 | 200000 (30) | 10+ | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Intake structure and foreay | 148 | 11 | No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack. | 4 | (60) | (20) | 2041 | | 2011 | Yes | Yes | 2000 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Pit, stoplogs and discharge | 149 | 11 | No recent underwater inspections of pit, stoplogs or outfall structures. | 4 | (60) | (20) | 2041 | | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8097 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS EAST | N/A | 150 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2012 | | Yes | No | 2000 |
| 1296 | 7635 | 8093 | 271486 | 8098 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS WEST | N/A | 151 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2012 | | Yes | No | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8821 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 152 | 11 | Significant corrosion. Likely near end of life. | 3a | (30) | (5) | 2041 | | | No | No | 1971 |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

1. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 cooling water systems associated with generators:

**TABLE 9-23 RECOMMENDED ACTIONS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 7703 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Aux Cooling Water Piping/Hexch | 181 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | TG Piping | 182 | 8 | Clean and coat remaining auxiliary cooling water piping. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Aux Cooling Water Piping | 183 | 8 | Perform representative Level 2 pipe thickness checks on seawater intake and discharge piping. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Aux Cooling Water Pipes | 184 | 8 | Perform Level 2 on auxiliary cooling pipes. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Aux CW Ht Exch | 186 | 8 | Perform Level 2 on auxiliary cooling heat exchangers. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 9622 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP SOUTH | TG Piping | 187 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 9624 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP NORTH | N/A | 188 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 7635 | 8093 | 7703 | 299550 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING STRUCTURE | N/A | 189 | 11 | Continue current condition monitoring. | 2011 | 2 |
| 1296 | 7635 | 8093 | 8132 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 191 | 12 | Continue current inspection and maintenance activities. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 203 | 11 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor be maintained to service all three units, in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | N/A | 204 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplog. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8097 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS EAST | N/A | 205 | 11 | Continue current condition monitoring. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8098 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS WEST | N/A | 206 | 1 | Continue current condition monitoring. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | N/A | 207 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplog. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8821 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 208 | 11 | Refurbish or replace. | 2011 | 2 |

### 9.1.4.6 Risk Assessment

Table 9-24 below illustrates the risk assessment for the Unit 2 cooling water systems associated with generators, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-24 RISK ASSESSMENT – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | ACW Piping | 160 | 8 | Corrosion, mechanical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Seawater Piping | 161 | 8 | Corrosion, mechanical failure. | (10) | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 7703 | 9622 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP SOUTH | ACW Pump/Motor | 162 | 8 | Mechanical or electrical failure. | (10) | None | 1 | A | Low | 1 | A | Low | Sparing, minimal. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 7703 | 9624 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP NORTH | ACW Pump/Motor | 163 | 8 | Mechanical or electrical failure. | (10) | None | 1 | A | Low | 1 | A | Low | Sparing, minimal. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 7703 | 299550 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING SCREENS | N/A | 164 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | ACW Cooling plugging | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 7703 | 299551 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING SCREENS | N/A | 165 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | ACW Cooling plugging | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Pump/Motor Failure | 166 | 12 | Mechanical or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Minimum | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Ht Exch Failure | 167 | 12 | Mechanical failure/pluggage. | 10 | None | 1 | A | Low | 1 | A | Low | Seawater contamination (unlikely). | Inspect and maintain. |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Piping Failure | 168 | 12 | Mechanical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Intake Structure | 181 | 11 | Structural cracking; steel corrosion. | (20) | None | 1 | B | Low | 1 | A | Low | Structural failure requiring shutdown. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8097 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS EAST | N/A | 182 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | Condenser plugging. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8098 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS WEST | N/A | 183 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | Condenser plugging. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | CW Outfall Piping | 184 | 11 | Concrete cracking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8821 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 185 | 11 | Corrosion, failure. | 5 | None | 2 | A | Low | 3 | A | Low | Screen pressure drop/load reduction. | Refurbish/replace. |

### 9.1.4.7 Life Cycle Curve and Remaining Life

Figure 9-9 below illustrates the life cycle curve for the Unit 2 cooling water systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them at this time, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

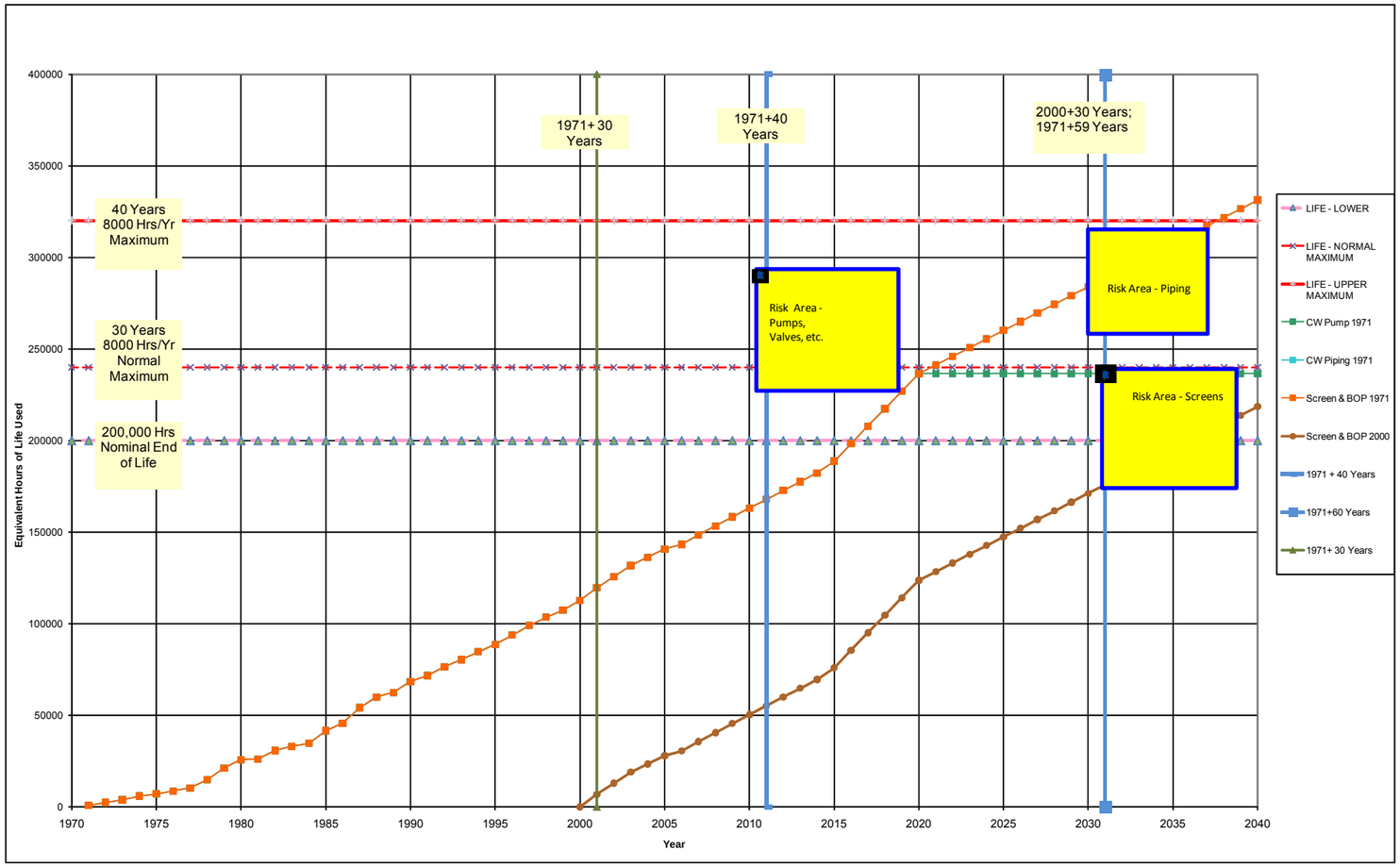



**FIGURE 9-9 LIFE CYCLE CURVE – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

The curve indicates that the remaining life (RL) of most elements of the Unit 2 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not necessarily the 2041 desired life (DL) end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. The intake and outfall structures and associated sub-components should be added as a result of a Level 2 inspection.

### 9.1.4.8 Level 2 Inspections – Unit 2 Cooling Water Systems Associated with Generators

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-25 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-25 LEVEL 2 INSPECTIONS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 0 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | None | 134 | N/A | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | seawater intake and discharge piping | 135 | 8 | Perform representative Level II pipe thickness checks. | 2011 | $6 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | AC Water piping | 136 | 8 | Thickness spot checks. | 2011 | $6 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Ht Exch | 137 | 8 | AC Water Ht Exchangers shell and tubes. | 2011 | $6 |
| 1296 | 7635 | 8093 | 7703 | 9622 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP SOUTH | CW Pumps | 138 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). | 2011 | |
| 1296 | 7635 | 8093 | 7703 | 9624 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP NORTH | CW Pumps | 139 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). | 2011 | |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | None | 140 | 12 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | None | 141 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | None | 142 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | CW intake and discharge structures and piping | 147 | 11 | Inspections – diver visual inspection. | 2011 | $30 |
| 1296 | 7635 | 8093 | 271486 | 8097 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS EAST | CW intake and discharge structures and piping | 148 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 271486 | 8098 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS WEST | None | 149 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 7703 | 299550 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING STRUCTURE | None | 150 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 7703 | 299551 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING STRUCTURE | None | 151 | 11 | No Level 2 required. | | |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | None | 152 | 11 | Inspections – diver visual inspection within 2 to 4 years. | 2011 | $30 |
| 1296 | 7635 | 8093 | 271486 | 8821 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | None | 153 | 11 | No Level 2 required. | | |

### 9.1.4.9 Capital Projects

The suggested typical capital enhancements include:

**TABLE 9-26 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | N/A | 126 | 8 | Clean and coat AC Water pipes. | 2012 | 2 |
| 1296 | 7635 | 8093 | 7703 | 9622 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP SOUTH | N/A | 127 | 8 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 7703 | 9624 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | T/G COOLING PUMP NORTH | N/A | 128 | 8 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 7703 | 299550 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING SCREENS | N/A | 129 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 7703 | 299551 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | CW TRAVELLING SCREENS | N/A | 130 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 8132 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 131 | 12 | None | | |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Intake structure and pit | 141 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8097 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS EAST | N/A | 142 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8098 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CWTRAVELLING SCREENS WEST | N/A | 143 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Outfall structure, pit, stoplogs | 144 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8821 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 145 | 11 | No capital investment required. | | |

## 9.2 Unit 2 – Lower Priority Systems

### 9.2.1 Asset 7786 Unit 2 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30, and 34)

The requirements for the boiler system servicing Unit 2 is as follows:

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7786 #2 Boiler Plant |
| Sub-Systems: | 7787 #2 Boiler Structure |
| | 7789 #2 Boiler F.W. & Sat. Steam |
| | 7810 #2 Boiler Superheater and Reheater |
| Components: | 7790 #2 Economizer, tubing and headers |
| | 7789 #2 Linking piping (boiler internal) |
| | 7789 #2 Furnace water circuit<br>7794 #2 Steam drum,<br>7789 #2 Downcomers and feeder piping as required<br>7789 #2 Lower Waterwall headers<br>7789 #2 Waterwall Tubing<br>7789 #2 Upper Waterwall headers, and riser piping as re |
| | 7811 #2 Superheater; headers and tubing |
| | 7835 #2 Reheater; headers and tubing |
| | 7789 #2 Safety Valves |
| | 7823 #2 Boiler Main Steam lines |
| | 7824 #2 Boiler Stop Valve |
| | 7787 #2 Furnace structural, hangers and casing |
| | 7945 #2 Boiler Blowdown Tank |

#### 9.2.1.1 Description

The Unit 2 boiler is a Combustion Engineering (now supported by ALSTOM), natural circulation, single reheat, pressurized unit. The boiler was originally designed in 1968 for an output of 150 MW with a maximum steam flow of 132.4 kg/s (1,050,000 lbs/hr), at 227 MPag (1800 psig) and 538 °C (1000 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 126 kg/s (921,000 lbs/hr) with an inlet temperature of 366 °C (690 °F) and an outlet temperature of 541 °C (1005°F). Unit 2 was commissioned in 1970.

Unit 2 was uprated to nominal output of 175 MW in 1988/1889. The boiler was analyzed to determine if this increased load could be accommodated by raising the superheat steam flow approximately 11% to 1,167,200 lb/hr and the reheat steam flow approximately 13% to 131 kg/s (1,044,630 lb/hr). Associated boiler pressure part modifications were evaluated such that the boiler design pressure of 15.2 MPag (2205 psig) could be maintained with the increased steam outlet pressure. All the pressure parts were analyzed for ASME Code compliance and optimized operation. In order to reduce anticipated attemperator spray water in the superheater section, heating surface was removed from the primary superheater sections. Additional modifications were made to the boiler non-pressure part equipment. After uprating, the boilers are rated at a maximum steam flow of 147 kg/s (1,167,000 lbs/hr), at 13.6 MPag (1970 psig) and 541 °C (1005 °F) with an inlet feedwater temperature of 240 °C (464 °F). The reheat steam flow was designed for 13.1 kg/s (104,500 lbs/hr) with an inlet temperature of 353 °C (667 °F) and an outlet temperature of 541 °C (1005 °F).

The system includes:

- Economizer, tubing and headers;
- Linking piping (boiler internal;
- Furnace water circuit;
    - Steam drum,
    - Downcomers and feeder piping as required
    - Lower Waterwall headers
    - Waterwall tubing
    - Upper Waterwall headers, and riser piping as required
- Superheater; headers and tubing;
- Reheater; headers and tubing ;
- Safety valves;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

Boiler #2 had superheater sections replaced in 2008. Boiler sootblowers were added in 1995. Unit 2 was upgraded in 1988 to 175 MW from 150 MW.

#### 9.2.1.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Major Inspection/Maintenance Repair | Annual May to Sep on all units |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |
| Max Hours Ops – 1986 to Dec 2009 | 113 |
| Max Hrs - 1986 to Dec 2015 | 142 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 164 |
| Max Hours Ops – 2007/8 to Dec 2009 | 5 |
| Max Hrs – 2007/8 to Dec 2015 | 35 |
| Max Hrs – 2007/8 to Gen End Date Dec 2020 | 59 |

#### 9.2.1.3 Inspection and Repair History

As a component of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers (inspection results were not available). The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 2:

**Asset 7790 Economizer**

During the 2002 outage, the economizer inlet header was opened for debris removal and internal visual inspection.

During the 2003 outage, a thermocouple was installed on economizer inlet header near inlet pipe.

During the 2004 outage, three rows of tube stubs from the economiser inlet header were exposed for inspection using shear wave UT inspection, starting with the second row from the west to find internal corrosion fatigue cracking similar to what caused the tube failure on Unit 1 in 2003. No evidence of damage was found. In addition, a visual internal inspection was done using a boroscope. The first two tube rows were inspected from the east handhole cap. This included an inspection of the first couple of inches inside the tubes and associated ligament areas. No defect could be seen. Also, the sootblower pipe supports were relocated from the header to the buckstay to eliminate expansion issues and any unnecessary loads on the header.

During October 2009, a tube leak was found in the economizer inlet header top west stub tube approximately 1 inch from the header on the top side of the tube. It was concluded that the failure was due to corrosion fatigue cracking similar to the incident that was observed on Unit 1 during 2003. The failed section of the tube was removed and replaced with available tube material (T11).

**Asset 7789 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes**

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after

boiler repairs. There were no internal inspections done for checking for ligament cracking or cracking at other locations. During 2007 outage, two upper waterwall headers (H3R and H4) were opened to determine if there was any blockage that could impact the circulation - particularly on the east side where the previous waterwall failures were concentrated. No problems were found. A couple of ligaments could be seen in H4 and there was no indication of any cracking. UT thickness measurement is taken on the waterwall circuit feeder and riser tubes. Some of the riser tubes were found in contact with each other during outage inspection, however no damage was noted.

**Asset 7794 Steam Drum**

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although a slight pitting was observed, but not active, it is not considered a pressure integrity issue for the steam drums. During the Unit 2 2005 outage, all the separators were removed for a detailed inspection of the internals and the shell. However, the baffles were not removed.

**Asset 7789 High Temperature Headers and Piping**

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on the selective tube to header welds on the superheater and reheater section headers, subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

During 2007 outage, SH5 and SH6 were opened on the east side for cleaning and inspection as part of the superheater work. During a boroscopic inspection of the superheater outlet header, significant scale was noted and there were sections where exfoliation had apparently occurred.

**Asset 7811 Superheater Link Piping and Attemperator**

A visual inspection of the superheater link piping is carried out during every outage. There was no internal inspection carried out on superheater attemperators during the 2001-2009 period.

**Asset 7790 Economizer Tubes**

In April of 2005, a tube leak was found in the second tube down from top in the third row from west side during the plant operation. It was a longitudinal crack approximately 9 cm (3.5 inches) long in the tube located at the support. Destructive examination of the tube sample established that the failure in the tube originated from one of two diametrically opposed cracks on the inside diameter (ID) surface of the seamless tube that were shown by metallurgical examination to be mill defects and failure mechanism was corrosion fatigue.

In October 2009, a tube leak was found in the economizer inlet header top west stub tube approximately 2.5 cm (1 inch) from the header on the top side of the tube. The section of the tube was replaced with T11 material. The leak was similar to the leak observed in Unit 1 in 2003.

**Asset 7789 Waterwall Tubes**

During April 2006, an NDE inspection of the furnace walls was completed in the burner zone between elevations 12.8 m (42 feet) and 19.8 m (65 feet) on the north, south and west walls and 2.4 m (8 feet) slope section of the roof, in order to check for internal tube damage. In addition, approximately 85.3 m (280 linear feet) of the east wall was scanned from the cold side. The Low Frequency Electromagnetic Technique (LFET) was used, with confirmation by UT. No defect was found in the slope roof tubes and

cold side of the east wall. However, some indications were found on the north, south and west walls. The east wall, from the second floor to the fourth floor, was replaced due to thinning, hydrogen damage and blistering caused by the internal fireside deposits that had caused number of tube failures. Also, tubes on the north, south and west walls that had shown damage during LFET inspection were replaced. Moreover, a boiler chemical clean was performed during the outage.

During the 2009 outage, two tube samples were removed from the high heat flux area at approximately top burner elevation. Also, a boroscope inspection was carried out through the tubes and those were found to be clean.

**Asset 7811, 7835 Superheater and Reheater Tubes**

The anti-vibration baffles were noted to be in very poor condition. There are minor tube alignment issues as some tubes had drifted laterally. However, the alignment did not appear to be worsening at that time. No significant tube thickness loss was discovered during the 2008 outage UT inspections at the selective locations on Unit 2. The tubes were well above the minimum wall thickness required. No tube sample analysis has been performed on the lower secondary superheater section on Unit 2. Also, tube thickness measurement data was not available for the lower section.

**Asset 7811 Secondary Superheater**

During the 2006 outage, surface replication was performed on the three tubes of lower secondary superheater section that had been found bowed up to 15 cm (6 inches) in the middle span to determine if there were any metallurgical concerns. There were no creep voids, cracks, or microfissures observed at any of the tube locations examined. During 2007, a partial replacement of the Unit 2 secondary superheater was carried out. A total of 30 of the 31 final superheater assemblies (except 7$^{th}$ platen), that were made of SA-213-TP-321H material were replaced because of severe thinning caused by OD corrosion. The new assemblies were fabricated from SA-213-347H stainless steel tubes with nominal wall thickness of 6.4 mm (0.2 inches). This was an upgrade from the original 321H tubes having nominal wall thickness ranging from 4.2 mm (0.165 inches) to 5.6 mm (0.220 inches). The assemblies were supplied with T22 (2¼ chrome) safe-ends for welding to the T22 tube ends in the boiler and vestibule. Thus the old DMWs (Dissimilar Metal Welds) were removed and replaced with new DMWs that were completed in the shop.

Broken welds were found in the saddle attachment welds between the hanger tubes and the superheater tubes during the 2009 outage. Only one had tube damage from failure and the others were broken in the weld. Most of them were repaired. During the 2009 outage it was observed that some superheater tubes had sagged down considerably.

**Asset 7835 Reheater**

Some tube wall thinning was observed in the reheater section. However, all measurements were above the ASME calculated thickness. There has been no tube failures observed in the reheater section. The DMWs were inspected at random locations to check for potential cracking using Liquid Penetrant Inspection (LPI) method.

**Asset 7789 Safety Valves, Casings, & Structure/Hangers**

Safety relief valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the desired life to 2020.

Casing: The casing has a history of failures at both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel structure and hangers - corrosion in the boilers penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

**Asset 7945/7948 Boiler Blow Down Tank**

The unit is inspected annually, except in 2009 and 2010. In 2009 the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

### 9.2.1.4 Condition Assessment

The condition assessment of the Unit 2 boiler system is illustrated below in Table 9-27:

**TABLE 9-27 CONDITION ASSESSMENT – UNIT 2 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 58 | 30 | No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem for main steam, hot reheat and cold reheat lines. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 59 | 30 | No information on recent inspections of the sample of the upper waterwall headers flat end welds | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 60 | 30 | High heat flux and challenging chemistry are related to numerous damage mechanisms on interior and exterior surfaces of waterwall tubing. No information on recent destructive testing reports of waterwall tubes that were removed in 2009. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Headers & link Piping | 61 | 30 | Economizer outlet headers or link piping to the steam drum in good condition. Thermal/corrosion fatigue related failure experienced in the economizer inlet headers stub tubes. Only partial internal and stub tube inspections on Unit 2 during 2004 outage. Failure in the outlet tube of Unit 2 economizer inlet header in 2009. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Tubing | 62 | 30 | Insufficient inspections to assess condition. Wall thickness review inconclusive - some 2009 readings decreased and some increased vs 2004. Corrosion fatigue failure of economizer tube in 2005 due to a manufacturing defect. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 7794 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 63 | 30 | No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 7801 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | FURNACE | N/A | 64 | 30 | See details below. | | | | | | | | | |
| 1296 | 7635 | 7786 | 7810 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | N/A | 65 | 30 | See details below. | | | | | | | | | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 66 | 30 | Design creep life calculations for secondary superheater outlet headers suggest concern. Internal scale noted in superheater outlet header during previous outage inspections. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Tubes | 67 | 30 | Insufficient inspections to assess damage. Wall thickness review inconclusive - some 2009 readings decreased and some increased vs 2004. Corrosion fatigue failure of economizer tube in 2005 due to a manufacturing defect. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Tubes | 68 | 30 | Partial replacement with upgraded materials of the secondary superheater sections in 2007 - expected to operate without failure up to the desired life. Destructive tube sample analysis is required for the lower secondary superheater section that was not replaced. Surface replication performed on three tubes lower secondary superheater section and no creep damage observed. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7813 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP'R | N/A | 69 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 70 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Headers & link Piping | 71 | 30 | Design creep life calculations for reheater outlet headers suggest concern. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Tubes | 72 | 30 | No inspections done (including destructive tube sample analysis) assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7789 | 7789 | 0 | 2 | #2 BOILER PLANT | BLR BLOWDOWN DRAINS | BOILER BLOWDOWN TANK | N/A | 73 | 30 | Thinning, corrosion. Sefety issues - isolation and access | 10 | 200000 (30) | (3) | 2020 | 2012 | 2012 | Yes | No | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | N/A | 74 | 30 | No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem (only Unit 3) for main steam, hot reheat and cold reheat lines. | 4 | 200000 (30) | (10) | 2020 | | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 75 | 30 | Reasonable condition. No detailed review. | 3a | 200000 (30) | (10) | 2020 | 2011 | 2011 | Yes | No | 2008 |

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 boiler system.

**TABLE 9-28 RECOMMENDED ACTIONS – UNIT 2 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 83 | 30 | See details below. | | |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 84 | 30 | Monitor pitting on the tubes adjacent to the burners. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 85 | 30 | Review the destructive testing 2009 report of waterwall tubes to evaluate the findings. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 86 | 30 | Inspect selective flat end welds of the upper waterwall headers. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 87 | 30 | Inspect the selective feeder and riser tubes for corrosion fatigue damage. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 88 | 30 | Perform preliminary internal inspection of lower waterwall headers at the locations of the degradation mechanisms identified for steam drum using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 89 | 30 | Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 90 | 30 | Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the economizer tube in Unit 2 in 2005. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 91 | 30 | Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 92 | 30 | Perform Level 2 inspections of the economizer inlet header:<br>1. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed.<br>2. UT inspection of stub tubes.<br>3. Sample stub tube to assess evidence of FAC. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7790 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 93 | 30 | During annual outages, visually inspect the economizer outlet headers and supports, and the economizer link piping to ensure there is no change in the state and/or abnormal movement. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7794 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 94 | 30 | Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7794 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 95 | 30 | Perform external inspection of feeder tube welds. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7794 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 96 | 30 | Manage steam drum target life with appropriate operational control and routine inspection and maintenance. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | N/A | 98 | 30 | Inspect SH-4, SH-6 and RH-2 for creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 99 | 30 | Inspect the presence of inside pitting and scaling. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 100 | 30 | Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues and failures of AVBs. | 2013 | 2 |

Table 9-28 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7810 | 7811 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 101 | 30 | Perform destructive tube sample analysis on the lower secondary superheater section that is not replaced to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. Similar confirmatory inspection is required for the part of upper superheater tubes that were replaced during Units 2 uprate in 1988/1989. | 2013 | 1 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 102 | 30 | Continue the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7811 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 103 | 30 | Refurbish the furnace exit thermoprobe and use during start-up activities. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7813 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP'R | N/A | 104 | 30 | Inspect attemperator and ID the link piping for evidence of thermal fatigue. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7830 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 105 | 30 | Inspect attemperator and ID the link piping for evidence of thermal fatigue. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 106 | 30 | Inspect to check the presence of inside pitting and scaling. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 107 | 30 | Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 108 | 30 | Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 109 | 30 | Enhance the present inspection and maintenance program to monitor and control failures of tube saddle supports and other alignment issues. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7835 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 110 | 30 | Assess and implement as economically justified, the addition of reheater surface for reheat temperature and efficiency. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | N/A | 111 | 30 | Implement an active high energy piping management program including NDE testing at key locations and a high temperature piping constant support hanger monitoring program. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7789 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER BLOWDOWN TANK | N/A | 112 | 30 | Replace tank | 2012 | 1 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVES | N/A | 113 | 30 | Inspect and refurbish/replace during next major boiler outage. | 2011 | 2 |

### 9.2.1.6 Risk Assessment

Table 9-29 below illustrates the risk assessment for the Unit 2 boiler system, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-29 RISK ASSESSMENT – UNIT 2 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Upper WW Headers | 68 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds, corrosion. | 10 | Could meet the desired life with routine inspections. | 2 | B | Low | 2 | C | Medium | Flat end weld cracking. Wall thinning due to corrosion. Unit outage. Safety. | Routine inspections. |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Riser Tubes | 69 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 2 | C | Medium | Wall thinning due to corrosion. Unit outage. Safety. | Inspections are required to assess remaining life. |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Lower WW Headers | 70 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking, corrosion. | (10) | No real life limiting issue. Additional inspections required. | 3 | B | Med | 3 | B | Medium | Ligament cracking and weld cracking. Unit outage. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Feeder Tubes | 71 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Corrosion fatigue cracking and wall thinning due to corrosion related mechanism. Unit outage. | Inspections are required to assess remaining life. |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Downcomers | 72 | 30 | Thermal/mechanical fatigue cracking at the header support locations. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Thermal/Mechanical Fatigue Cracking at the header support locations. Unit outage. Safety. | Inspections are required to assess remaining life. |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Waterwall Tubes | 73 | 30 | Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion. | 10 | Pitting in some areas require attention, other than that no major life limiting issue observed. | 3 | B | Med | 3 | B | Medium | Extensive pitting leading to tube failure. Unit derate/outage. | Some sections of floor tubes and pitting in some areas require attention. |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Inlet Headers | 74 | 30 | Thermal/mechanical fatigue cracking, corrosion fatigue cracking, corrosion, FAC. | (10) | No real issue as per inspection to date. Additional inspections required. | 3 | B | Med | 3 | B | Medium | Ligament cracking, tube stub thinning/cracking, weld cracking. Unit derate/outage. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 75 | 30 | Mechanical fatigue cracking, corrosion fatigue cracking, corrosion. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Weld cracking due to support failure. Unit derate/outage. | Routine inspections. |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Tubes | 76 | 30 | External corrosion and corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 1 | B | Low | 1 | B | Low | Tube failure due to corrosion, corrosion-fatigue. Unit derate. | Inspections are required to assess remaining life. |
| 1296 | 7635 | 7786 | 7789 | 7794 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | Steam Drum | 77 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking. | 10 | No real issue as per inspection to date. Additional inspections required. | 3 | C | Med | 3 | C | High | Ligament cracking. Weld cracking. Unit outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | Secondary Superheater Tubes (Lower) | 79 | 30 | Creep, OD/ID corrosion, ID pitting and sagging. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | C | High | Tube failure due to creep and creep fatigue, OD/ID corrosion, ID pitting. Outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989) | 80 | 30 | Creep, OD/ID corrosion, ID pitting and stress corrosion cracking. | (10) | Inspections are required to assess the remaining life. | 2 | C | Med | 2 | C | Medium | Creep, fatigue and stress corrosion, cracking damage, and wall thinning due to corrosion and pitting. Unit outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage) | 81 | 30 | Creep, OD/ID corrosion, ID pitting and stress corrosion cracking. | 10 | This section is relatively new and could meet the desired life. | 1 | C | Low | 1 | C | Low | Creep, fatigue and stress corrosion, cracking damage, and wall thinning due to corrosion and pitting. Unit outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Steam Cooled Walls Outlet Header | 82 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Medium | Thermal fatigue cracking. Unit outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Inlet | 83 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Medium | Thermal fatigue cracking. Outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Outlet | 84 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | C | Low | 1 | D | Medium | Creep and thermal fatigue cracking. Outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Support Tube Inlet Header | 85 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | C | Med | 2 | D | Medium | Creep and thermal fatigue cracking. Outage and life safety. | Additional inspections required to assess the remaining life. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Platen Inlet | 86 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | C | Low | 1 | D | Medium | Creep and thermal fatigue cracking. Outage and life safety. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Space Outlet | 87 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. Outage and life safety. | Additional inspections required to assess the remaining life. |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 88 | 30 | Fatigue, OD/ID corrosion, ID pitting. | 10 | No real life limiting issues; however, the presence inside pitting and scaling is not known. | 1 | C | Low | 1 | D | Low | Tube failure due to excessive pitting and corrosion. Unit outage. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7813 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP'R | Superheater Link Piping and Attemperator | 89 | 30 | Thermal/mechanical fatigue, corrosion fatigue, corrosion. | (10) | No real issue as per external visual inspection to date. Additional inspections required. | 1 | C | Low | 1 | D | Medium | Thermal/mechanical fatigue cracking, corrosion-fatigue cracking, wall thinning due to corrosion related mechanisms. | Additional inspections required. |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 90 | 33 | Not Addressed in detail. Mechanical failure. | (10) | Additional inspections required to assess the remaining life. | 3 | B | Medium | 3 | C | High | Inspection and refurbish or replace. | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Hot Reheat | 91 | 33 | Thermal/mechanical fatigue, creep, creep fatigue, corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations. | 3 | C | Med | 3 | D | High | Pipe and/or weld failures at potentially high stress locations. Outage and life safety. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations. Hanger/Support Inspection and Monitoring Program. Level 2 assessments. |

Table 9-29 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Cold Reheat | 92 | 33 | Thermal/mechanical fatigue, corrosion fatigue, cracking, corrosion. | (10) | No seam-welded pipe. No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns. Walkdown summary part describes specific observations. | 1 | B | Low | 1 | D | Low | Pipe and/or weld failures at potentially high stress locations Outage and life safety. | Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level 2 assessments |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Inlet Header | 93 | 30 | Thermal fatigue. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Thermal fatigue cracking. Outage and life safety. | Inspect and maintain. |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Outlet Header | 94 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. Outage and life safety. | Inspect and maintain. |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Tubes | 95 | 30 | Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | D | High | Creep, fatigue and stress corrosion, cracking damage, wall thinning due to corrosion and pitting and DMW failures. Unit outage. | Inspect and maintain. |
| 1296 | 7635 | 7786 | 7789 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER BLOWDOWN TANK | N/A | 95 | 33 | Not addressed in detail. Thermal/mechanical fatigue. | (2) | Safety issue. End of life. | 2 | B | Medium | 3 | C | High | Mechanical failure. Steam leak. Personal injury. | Replace |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | Main Steam | 96 | 33 | Thermal/mechanical fatigue, creep, creep fatigue, corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (more than 60% for Units 1 & 2 and more than 25% for Unit 3 at the end of 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for Units 1 & 2 (1987 to 2002); carbide particles in ferrite matrix; no significant crack or damage were found. No major damage found during walkdowns. Walkdown summary part describes specific observations. | 3 | D | High | 3 | D | High | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations. Outage and life safety. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations. |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 97 | 33 | Thermal/mechanical fatigue, creep, creep fatigue, corrosion. | (5) | Additional inspections required to assess the remaining life. | 3 | C | Medium | 3 | C | High | Inspection and refurbish or replace. | |

### 9.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 2 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30.The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

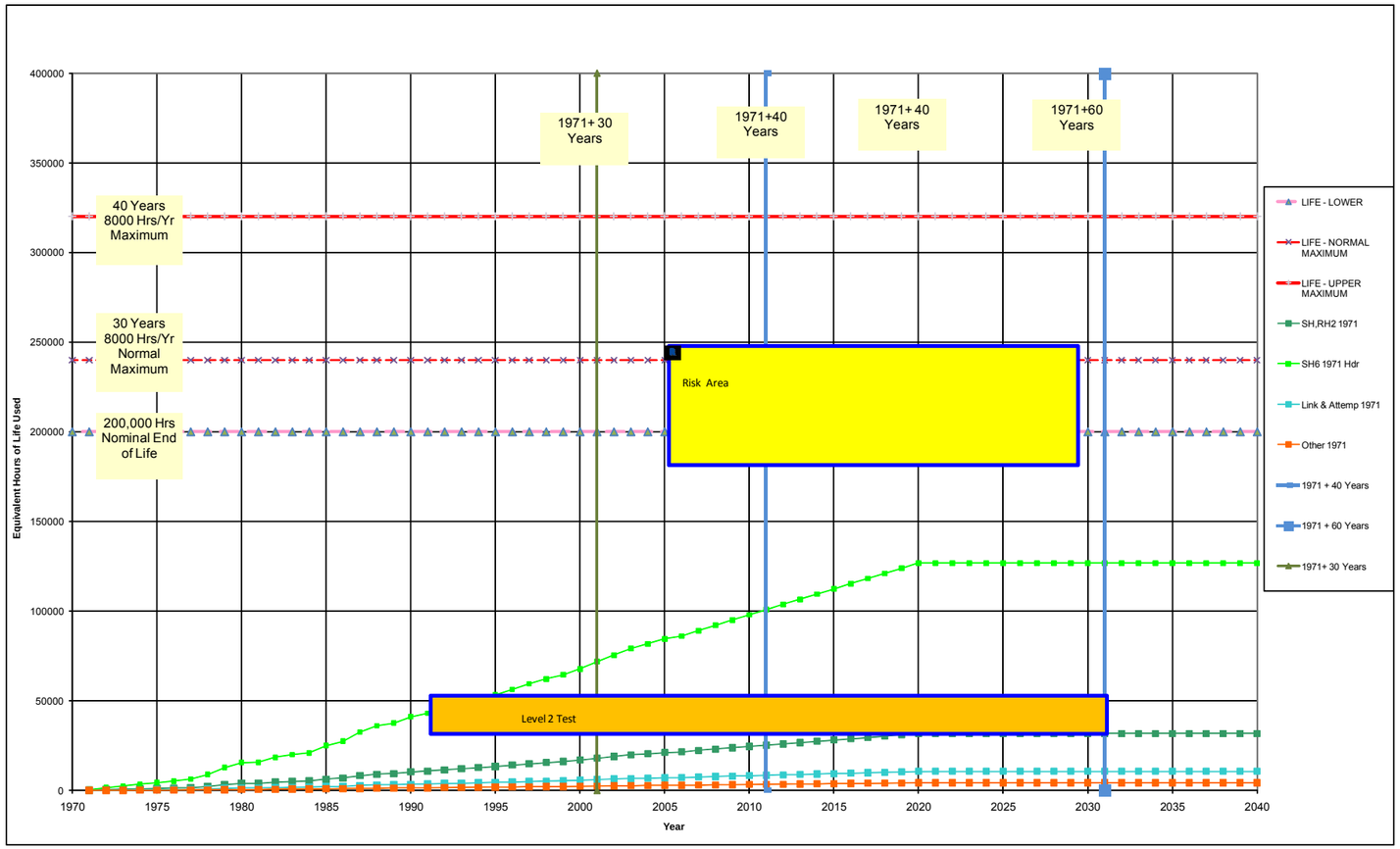



**FIGURE 9-10 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM – BOILER HEADERS**

The header life curves indicate that the remaining life (RL) of the Unit 2 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature (similar to the boiler headers) and to the material properties of the steam lines. Details are included in Appendix 33.The life curves are plots on the y-axis of current and projected “consumed equivalent life hours” based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life). The main steam life consumption is higher because it operates at both high temperature and high pressure. The hot reheat lines operates at comparable temperatures, but at lower pressures. The cold reheat line operates at both lower temperature and pressure. All values take into consideration the pipe materials used.

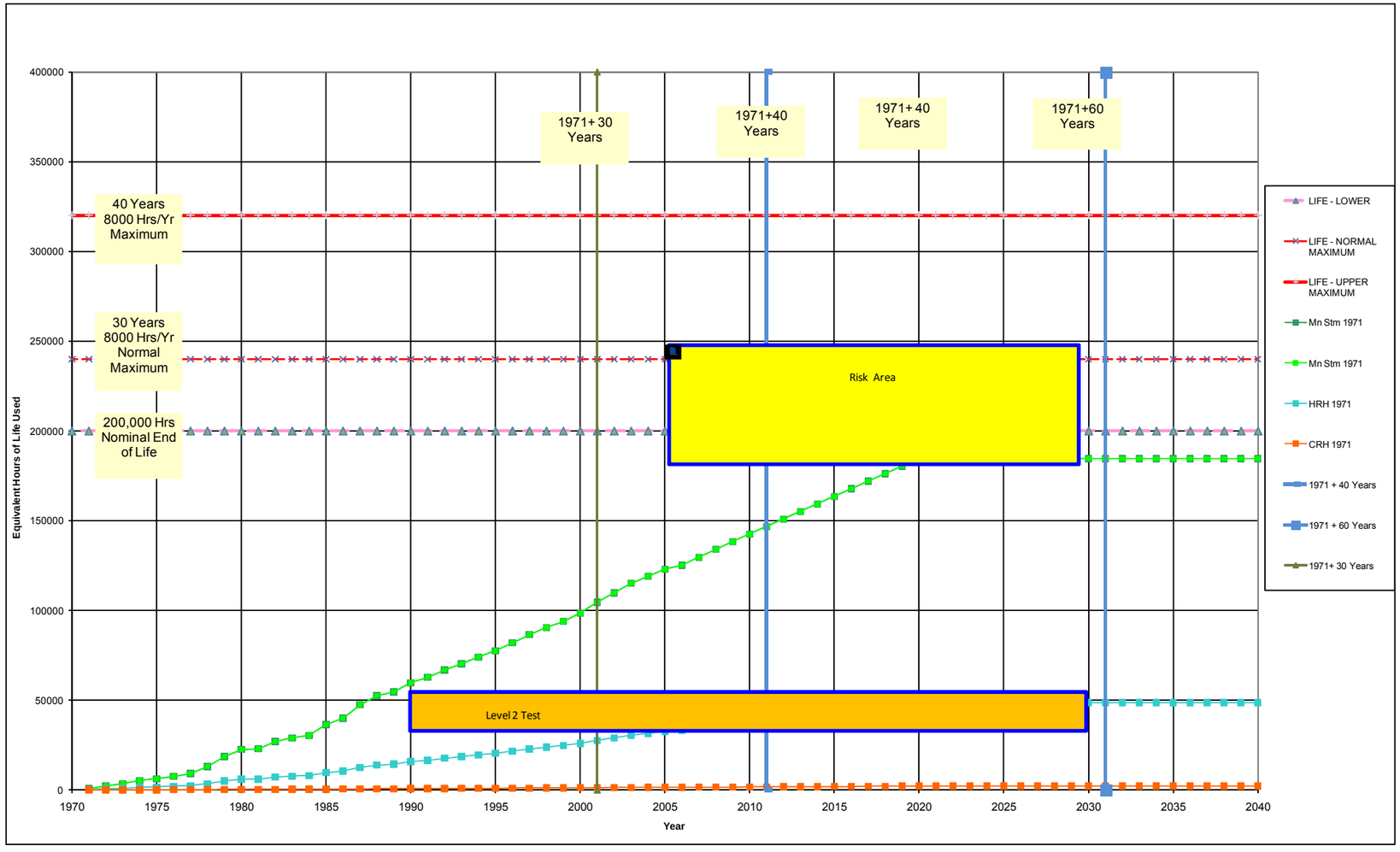



**FIGURE 9-11 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM – HIGH PRESSURE AND TEMPERATURE STEAM LINES**

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 2 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless it also identifies that both the main steam and hot reheat steam lines exceed EPRI’s 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 2 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium, moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

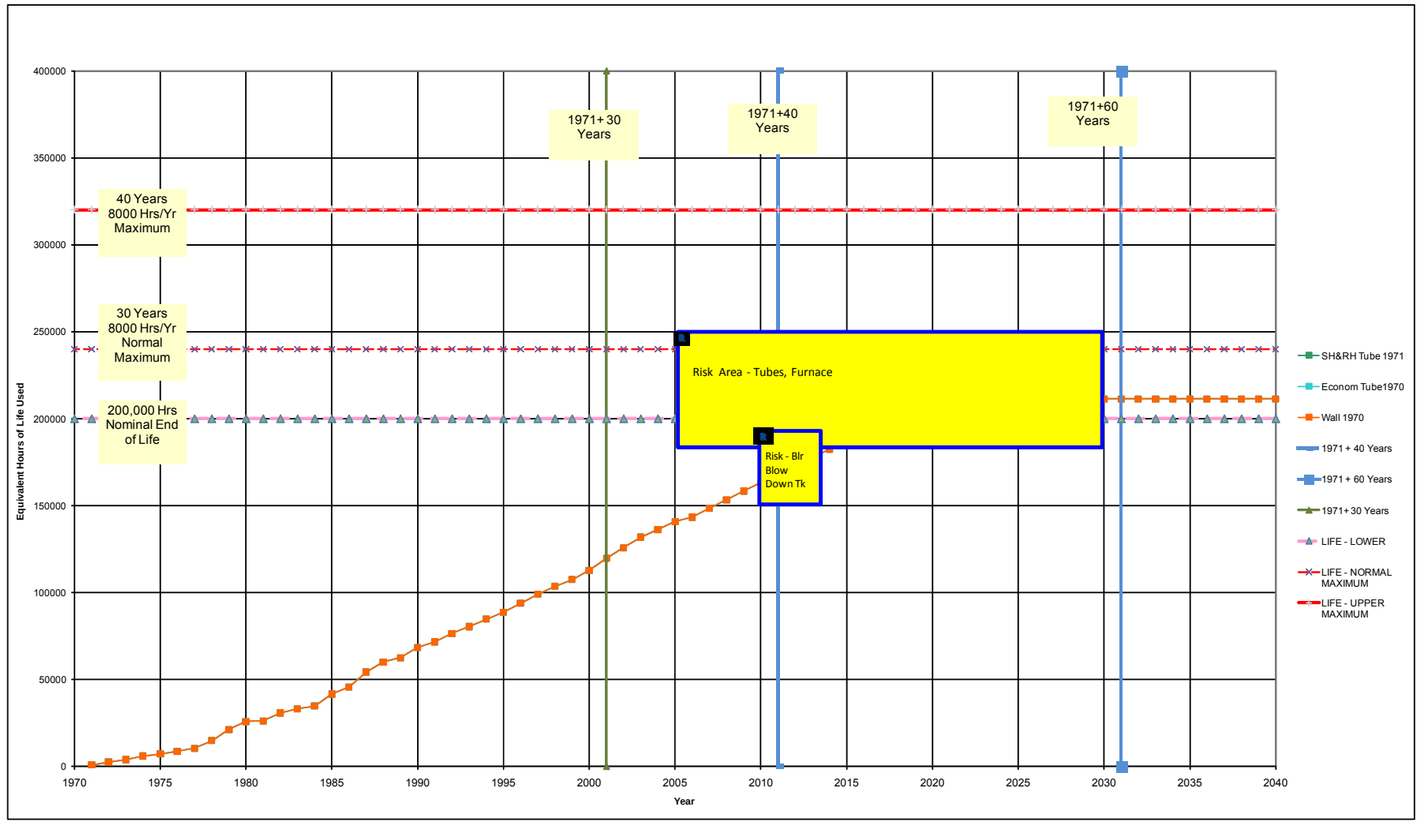



**FIGURE 9-12 LIFE CYCLE CURVE – UNIT 2 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS, BOILER BLOWDOWN)**

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

### 9.2.1.8 Level 2 Inspections – Unit 2 Boiler System

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-30 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-30 LEVEL 2 INSPECTIONS – UNIT 2 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 47 | 30 | Level 2 - Covers all boiler pressure part system costs - economizer, reheat, superheat, drum. See individual items for technical details. | 2013 | 2 | $1,476 |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Upper WW Headers | 48 | 30 | Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds. | 2013 | 3 | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Riser Tubes | 49 | 30 | Inspection of selective riser tubes for corrosion fatigue cracking. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Lower WW Headers | 50 | 30 | Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Feeder Tubes | 51 | 30 | Inspection of selective feeder tubes for corrosion fatigue cracking. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Downcomers | 52 | 30 | Inspections of thermal/mechanical fatigue damage at the headers support locations. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Waterwall Tubes | 53 | 30 | Assessment of the floor tubes wall thinning. Evaluation of pitting on the tubes adjacent to burners and on the waterwall slope under the economizer. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Inlet Headers | 54 | 30 | Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 55 | 30 | External visual inspection to ensure that there is no change in the state and/or abnormal movement. | 2013 | 3 | |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Tubes | 56 | 30 | Sample tubes removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage due to mill defects that had caused a failure in the unit economizer tube in Unit 2 in 2005. | 2013 | 3 | |
| 1296 | 7635 | 7786 | 7789 | 7794 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | Steam Drum | 57 | 30 | Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds. | 2013 | 2 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Steam Cooled Walls Outlet Header | 60 | 30 | No Level 2 required. | | 3 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Inlet Header | 61 | 30 | No Level 2 required. | | 3 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Rear Horizontal Spaced Outlet Header | 62 | 30 | No Level 2 required. | | 3 | |

Table 9-30 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Support Tube Inlet Header | 63 | 30 | Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Platen Inlet Header | 64 | 30 | No Level 2 required. | | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Front Horizontal Space Outlet Header | 65 | 30 | Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Superheater Link Piping and Attemperator | 66 | 30 | Inspections for assessment of damage caused by thermal/mechanical fatigue cracking, corrosion fatigue cracking and corrosion. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 67 | 30 | Inspections to check the presence of inside pitting and scaling. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7813 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP'R | None | 68 | 30 | No Level 2 required. | | |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | Reheater Inlet Header | 69 | 30 | No Level 2 required. | | |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | Reheater Outlet Header | 70 | 30 | Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | Reheater Tubes | 71 | 30 | Destructive tube sample analysis to assess the extent of the damage due to creep. ID liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMWs. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Tubes (Lower) | 72 | 30 | Inspections to assess the extent of the damage due to creep, sagging, ID liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the uprate in 1988/1989) | 73 | 30 | Inspections for creep, fatigue, corrosion, pitting and stress corrosion cracking. | 2013 | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Tubes (Upper part that was replaced during the 2008 outage) | 74 | 30 | No Level 2 required. | | |
| 1296 | 7635 | 7786 | 7789 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER F/W & SAT'D STEAM SYS | BOILER BLOWDOWN TANK | | 74a | 33 | No Level 2 required. | | |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 75 | 33 | Level 2 testing of steam and high pressure feedwater lines. | 2011 | $395 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STIOP VALVES | None | 76 | 33 | Level 2 testing of boiler stop valves as part of Main Steam Lines Program. | 2011 | $30 |
| 1296 | 7635 | 7786 | 7787 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | | 77 | 17 | No Level 2 required. | | |

### 9.2.1.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 57 | 30 | Install nitrogen blanketing. No other capital investment, pending Level 2 or next inspection. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 58 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7789 | 7790 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 59 | 30 | None, pending Level 2 or next inspection. Possible new recirculation line. | | |
| 1296 | 7635 | 7786 | 7789 | 7794 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 60 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7789 | 7801 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | FURNACE | N/A | 61 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER SUPERHEATER & | N/A | 62 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 7811 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER PRIMARY SUPERHEATER | N/A | 63 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 7813 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER SUPERHEATER | N/A | 64 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 7830 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER REHEATER ATTEMPERATOR | N/A | 65 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 66 | 30 | Implement addition of RH surface to match design temperatures and efficiency, subject to decision on Holyrood. | 2014 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER BLOWDOWN TANK | N/A | 67 | 30 | Replace tank | 2012 | 1 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER MAIN STEAM LINES | N/A | 68 | 30 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & | BOILER STOP VALVE | N/A | 69 | 30 | None, pending Level 2 or next inspection. | | |

### 9.2.2 Asset 7978 – Unit 2 Feedwater System High Pressure (HP) Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7976 #2 Condensate & Feedwater System |
| Sub-Systems: | 8059 #2 High Pressure Feedwater |
| Components: | 8066 #2 H.P. Heater 4 |
| | 8067 #2 H.P. Heater 5 |
| | 8068 #2 H.P. Heater 6 |
| | 8859 #2 Boiler Feed Pump East |
| | 8860 #2 Boiler Feed Pump West |

#### 9.2.2.1 Description

The high pressure (HP) feedwater systems servicing Unit 2 contains three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heater is a horizontally mounted, 100% capacity pressure vessel of U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of the HP feedwater heater. The main components of the HP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tub support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The tube material for all three HP feedwater heat exchangers is stainless steel SA-688.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 2. The pumps are multiple stage barrel centrifugal pumps. Each can provide up to 60% of the full load requirement. They have been in service since 1971, with some upgrades when the unit was uprated in 1989. The pump motors are 4 kV with a power rating of approximately 2000 kW. They directly drive the pumps. There is no variable speed device such as variable frequency drives or fluid couplings.

#### 9.2.2.2 History

The requirements for the Unit 2 generators are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses vary for systems/equipment that has been replaced (specifically the HP5 heat exchangers) are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

| | Unit 2 | | |
|---|---|---|---|
| | **HP-4** | **HP-5** | **HP-6** |
| Year Installed | 1988 | 2009 | 1988 |

#### 9.2.2.3 Inspection and Repair History

There have been no NDE inspections carried out on the currently in service HP feedwater heat exchangers in the past apart from tube leak testing. Other than yearly leak checks, no NDE has been performed on LP heat exchangers either. A long term commitment (life-cycle management plan) is required to diagnose and track all the failures to identify possible remedial actions so as to preclude similar future occurrences and provides the best chance for optimizing feedwater heater.

The Unit 2 HP feedwater heat exchangers HP-4 and HP-5 have the same operating life as the feedwater heater HP-5 that was replaced in 2009 due to excessive tube failures due to Stress Corrosion Cracking (SCC). The HP feedwater heater HP-5 is exposed to higher temperature than HP-4 and HP-6; otherwise HP-4 and HP-6 would have been exposed to the similar environment as HP-5. Hence, Level 2 inspections are required in order to assess the remaining life on Unit 2 HP-4 and HP-6 feedwater heat exchangers.

The Unit 2 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the motors are at a stage in life where failures may be anticipated.

### 9.2.2.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system – HP feedwater heat exchangers is illustrated below in Table 9-32:

**TABLE 9-32 CONDITION ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8037 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 119 | 23 | 4160V Motor annual tests. On-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pumps, using a spare barrel, are refurbished approximately every seven to years. | 3a | 200000 (30) | 10 | 2020 | 2012 | 2012 | Yes | No | 1971/1989 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 120 | 23 | Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2002 - next planned for 2011. | 3a | 200000 (30) | 10+ | 2020 | 2011 | 2012 | Yes | Yes | 1971/1989 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Motors | 121 | 23 | Motors installed in 1989. | 3a | (25) | (5+) | 2020 | 2011 | 2012 | Yes | No | 1989 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 122 | 23 | Pumps installed in 1969 and motors in 1989. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2004, next planned for 2012. | 3a | 200000 (30) | 10+ | 2020 | 2012 | 2012 | Yes | Yes | 1971/1989 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Motors | 123 | 23 | Motors installed in 1989. | 3a | (25) | (5+) | 2020 | 2012 | 2012 | Yes | No | 1989 |
| 1296 | 7635 | 7978 | 8059 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 124 | 32,33 | No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC. | 4 | 150000 (20) | (5) | 2020 | 2012 | 2013 | Yes | Yes | 1971 |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 125 | 32 | Installed 1985. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced. Plugged in order to satisfy the short-term problem. Cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2012 | 2013 | Yes | Yes | 1988 |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 126 | 32 | Replaced in 2009. | 4 | (20) | 20 | 2020 | 2012 | 2013 | Yes | Yes | 2009 |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 127 | 32 | Installed 1988. No NDE inspections carried out on the currently in service HP feedwater heaters. HP feedwater tube leaks experienced. Plugged in order to satisfy the short-term problem. Cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2012 | 2013 | Yes | Yes | 1988 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system – HP feedwater heat exchangers:

**TABLE 9-33 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8037 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 170 | 23 | Assess potential for variable speed control of BFW pumps. | 2011 | 2 |
| 1296 | 7635 | 7978 | 8037 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 171 | 23 | Assess potential for spare BFP motor and subsequent refurbishment/rewind of Unit 3 motors. | 2011 | 2 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 172 | 23 | Maintain current program of ongoing inspections and overhauls | 2011 | 2 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 173 | 23 | Maintain current program of ongoing inspections and overhauls | 2011 | 2 |
| 1296 | 7635 | 7978 | 8059 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 174 | 32 | See details below. | | |
| 1296 | 7635 | 7978 | 8059 | 8066 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 175 | 32 | Perform Level 2 inspections. | 2013 | 2 |
| 1296 | 7635 | 7978 | 8059 | 8067 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 176 | 32 | Perform Level 2 inspections. | 2013 | 2 |
| 1296 | 7635 | 7978 | 8059 | 8068 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 177 | 32 | Perform Level 2 inspections. | 2013 | 2 |

### 9.2.2.6 Risk Assessment

Table 9-34 below illustrates the risk assessment for the Unit 2 feedwater system – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-34 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7978 | 8037 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | Feedwater Discharge | 148 | 33 | Flow Accelerated Corrosion (FAC), thermal/mechanical fatigue cracking, corrosion-fatigue cracking; corrosion. | 10 | Major issue is FAC; No NDE inspection or material testing has been done in recent past. Not possible to assess current condition or remaining life. | 3 | D | High | 3 | D | High | Conduct sample FAC inspections using EPRI methodology. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | FW Pump East | 149 | 23 | Seal, bearing, impeller failure. | 10+ | Could meet the desired life; continued inspections/overhauls required . | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction. | Current inspection and maintain. |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | 4 kV Boiler Feed Pump Motor | 150 | 25 | Electrical fault, mechanical fatigue, ops error. | (5+) | >2020 with regular inspection, maintenance. | 1 | C | Low | 1 | B | Low | Loss 60% unit generation for extended time. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | FW Pump West | 151 | 23 | Seal, bearing, impeller failure. | 10+ | Could meet the desired life; continued inspections/overhauls required. | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction. | Current inspection and maintain. |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | 4 kV Boiler Feed Pump Motor | 152 | 25 | Electrical fault, mechanical fatigue, ops error. | (5+) | >2020 with regular inspection, maintenance. | 1 | C | Low | 1 | B | Low | Loss 60% unit generation for extended time. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7978 | 8059 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | All HP Feedwater Heaters | 153 | 32 | SCC, thermal/ mechanical fatigue. | (10) | Life management program is required. | 1 | C | Low | 2 | B | Low | Excessive tube failure event resulting in Turbine water induction. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | Unit #2 HP Feedwater Heater #4 | 154 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Medium | 2 | B | Medium | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | Unit #2 HP Feedwater Heater #5 | 155 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Brand new Heater can meet the desired life with routine inspections. | 1 | B | Low | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | Unit #2 HP Feedwater Heater #6 | 156 | 32 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Medium | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |

### 9.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 2 feedwater system - HP feedwater heat exchangers and Unit 2 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the Unit 2 feedwater system - HP feedwater heat exchangers, individual curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

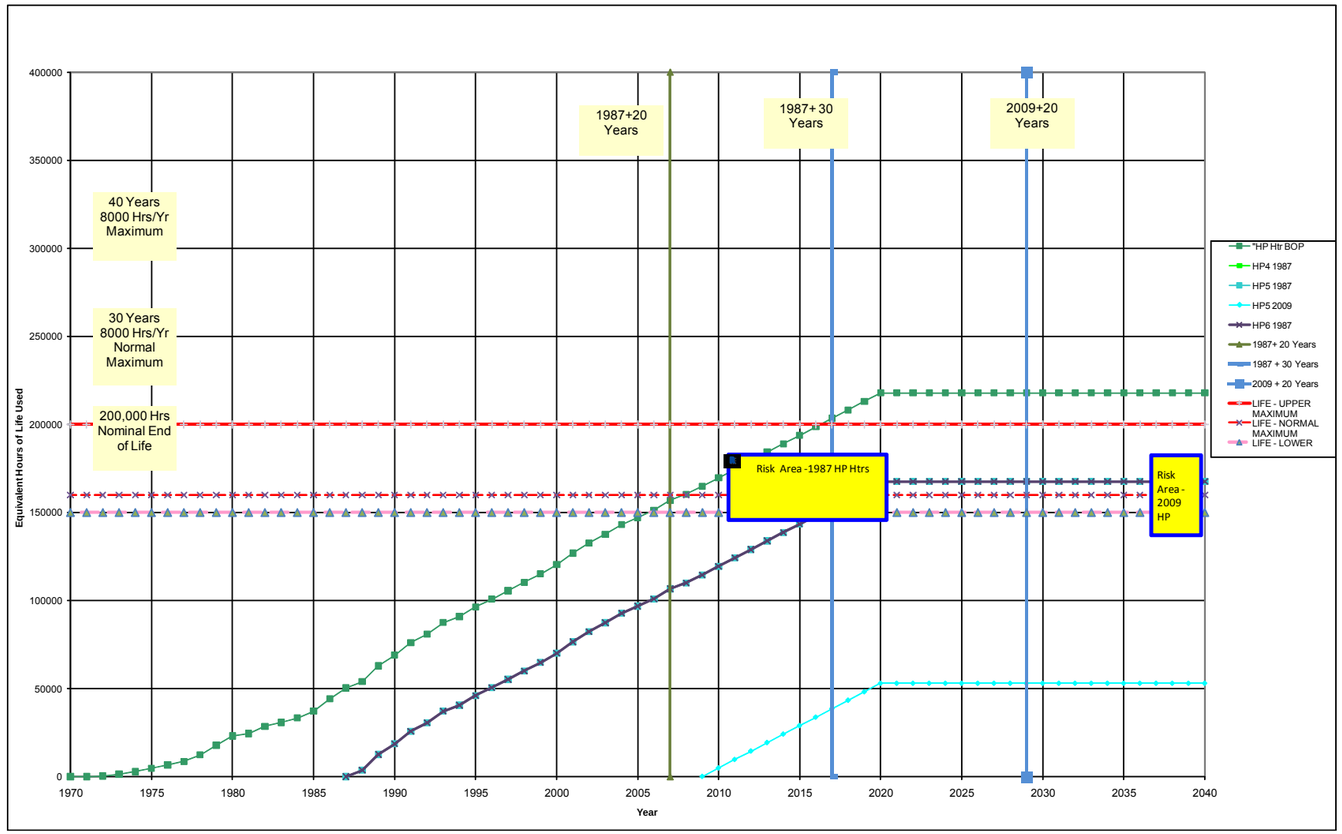



**FIGURE 9-13 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS -**

The curves indicate that the remaining life (RL) of the Unit 2 HP feedwater heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2013.

For the Unit 2 boiler feed pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

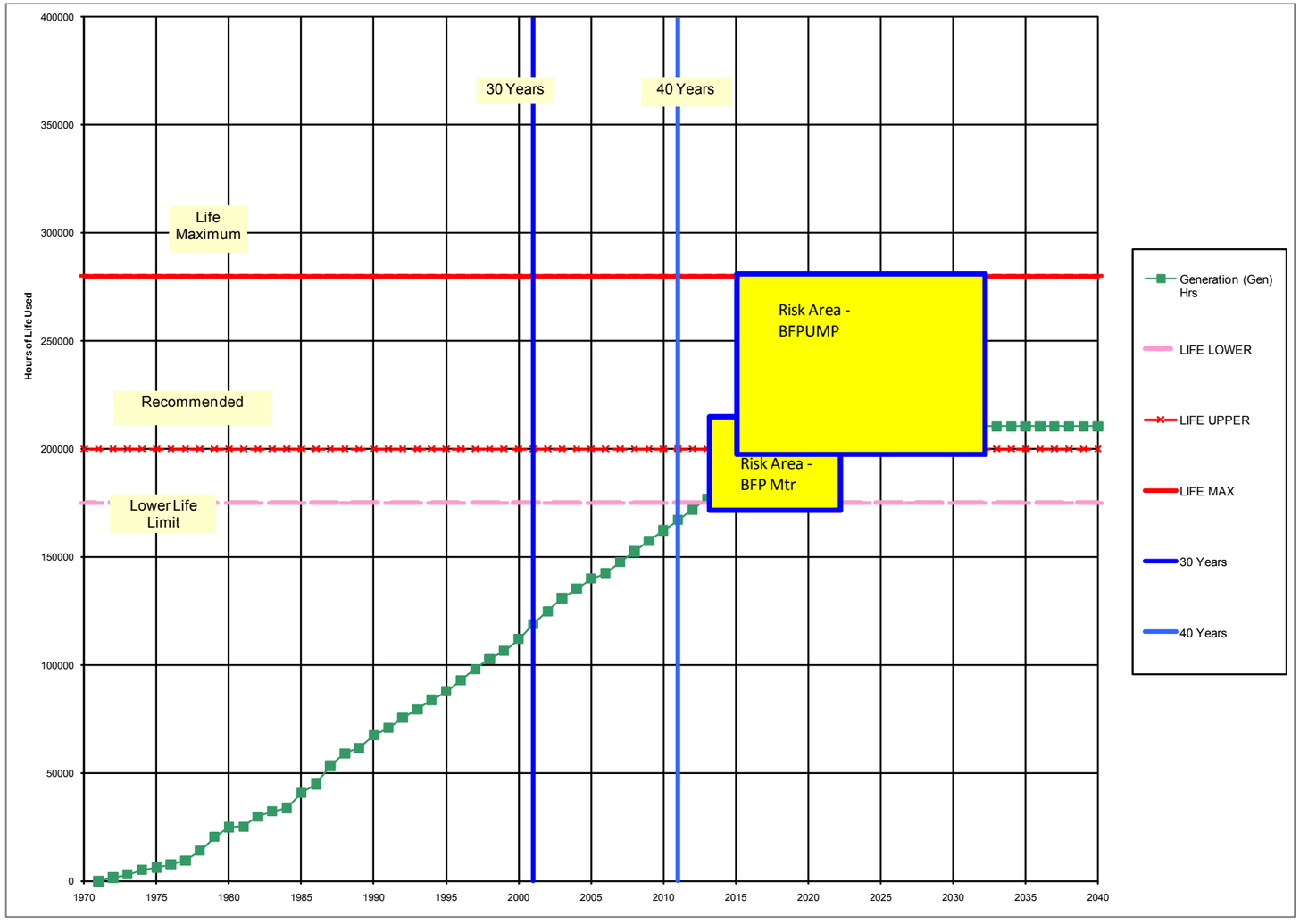



**FIGURE 9-14 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - BOILER FEED PUMPS**

The curve indicates that the remaining life (RL) of the Unit 2 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

### 9.2.2.8 Level 2 Inspections – Unit 2 Feedwater System - HP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-35 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-35 LEVEL 2 INSPECTIONS – UNIT 2 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 122 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 123 | 32 | Assessment of the tube plug map. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 124 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 125 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 126 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 127 | 32 | Assessment of the tube plug map. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 128 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 129 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 130 | 32 | Shell side inspections and channel side for the degradation mechanisms. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 131 | 32 | Assessment of the tube plug map. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 132 | 32 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2013 | 2 | |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 133 | 32 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2013 | 2 | |

### 9.2.2.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM – HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8037 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 112 | | No capital investment required. | | |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 113 | 23 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 3 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 114 | 23 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and, if practical, Unit 3 motors as required. | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | N/A | 115 | 23 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 116 | 23 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 3 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 117 | 23 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required. | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | N/A | 118 | 23 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 7635 | 7978 | 8059 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 119 | 32 | No capital investment required. | | |
| 1296 | 7635 | 7978 | 8059 | 8066 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 120 | 32 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 121 | 32 | Replace HP Htr 5 - similar to Unit 1. | 2013 | 1 |
| 1296 | 7635 | 7978 | 8059 | 8068 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 122 | 32 | None, pending Level 2 or next inspection. | | |

### 9.2.3 Asset 8017 – Unit 2 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7976 #2 Condensate & Feedwater System |
| Sub-Systems: | 7992 #2 Low Pressure Feedwater System |
| Components: | 8017 #2 Deaerator System (Deaerator and Deaerator Storage Tank) |

#### 9.2.3.1 Description

Deaerator systems consist of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 2 deaerator is a horizontal spray type, with the deaerator mounted on the horizontal deaerator storage tank.

The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the each deaerator vessel.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater to lower the potential for corrosion in the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods.

The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heater drains are fed to the deaerator. The BFP recirculation is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One end is anchored and the other support is free to allow thermal expansion.

#### 9.2.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

#### 9.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessels internal visual inspections and NDE of the selective welds were carried out in accordance with the plant annual inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessels as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from years 2001 to 2009.

**Deaerator**

- Cracks in the stainless steel liner;
- Warped stainless liner causing sealing issues for spray nozzles;
- Loose trays;
- Circumferential ridges in the deaerator shells on both the north and south sides;
- Minor corrosion, pitting and wall thinning, possibly due to flow accelerated corrosion in the bottom of the shells, was noted when a section of trays was removed in 2005; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

**Deaerator Storage Tank**

- Corrosion fatigue was found in the storage tank on the inside surface of the shell around the saddle support locations during the 2003 inspections. All damage was removed and the thickness of the tank was restored by pad welding. A semi-circle was cut in the centre gusset plates in the saddles to increase flexibility. Also, the stitch weld between the vessel shell and saddle plate was removed at the centre gusset plate location. Corrosion fatigue was not observed during subsequent inspections at these locations; and
- Light pitting has been observed on the inside surfaces in general and especially around the weld seams and in the bottom of shells.

### 9.2.3.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system - deaerator is illustrated below in Table 9-37:

**TABLE 9-37 CONDITION ASSESSMENT– UNIT 2 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 116 | 31 | No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels observed. Wall thinning observed in the bottom of the deaerator shells. Ridges observed may be due to erosion. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2013 | Yes | Yes | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system - deaerator.

**TABLE 9-38 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 159 | 31 | See details below. | | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 160 | 31 | Perform Level 2 inspections. | 2013 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 161 | 31 | Implement ongoing inspections and performance testing based on industry practices. | 2013 | 3 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 162 | 31 | Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside if not repaired yet. | 2013 | 3 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 163 | 31 | Refurbish manway seating surfaces that are in poor condition. | 2013 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 164 | 31 | Monitor pitting corrosion in the deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerator. | 2013 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 165 | 31 | Investigate the root cause of the ridges observed in deaerator vessels. | 2013 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 166 | 31 | Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank. | 2013 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 167 | 31 | Evaluate condition of spray nozzles that were observed eroding in Unit 3. | 2013 | 2 |

### 9.2.3.6 Risk Assessment

Table 9-39 below illustrates the risk assessment for the Unit 2 feedwater system - deaerator, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-39 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | Deaerators | 143 | 31 | Corrosion-fatigue, thermal fatigue, corrosion and FAC. | (10) | No real life limiting issue as per inspection to date. Additional inspections required. | 3 | B | Medium | 3 | B | Medium | Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | Deaerator Storage Tanks | 144 | 31 | Corrosion-fatigue, thermal fatigue, corrosion and FAC. | (10) | No real life limiting issue as per inspection to date. Additional inspections required. | 2 | B | Low | 2 | B | Low | Weld cracking, corrosion fatigue cracking, pitting corrosion cracking and support failure. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | Deaerators/ Storage Tanks | 145 | 31 | Corrosion fatigue and thermal fatigue. | (10) | No evidence of susceptibly during limited inspection to date. Ongoing monitoring required. | 1 | D | Medium | 1 | D | Low | Catastrophic failure at seam weld. | Inspect and maintain. |

### 9.2.3.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 feedwater system - deaerator is illustrated below. One curve is used as the major elements of the deaerator are largely of the same age and condition. The life curve is a plot of current and projected operating hours in generation mode only on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

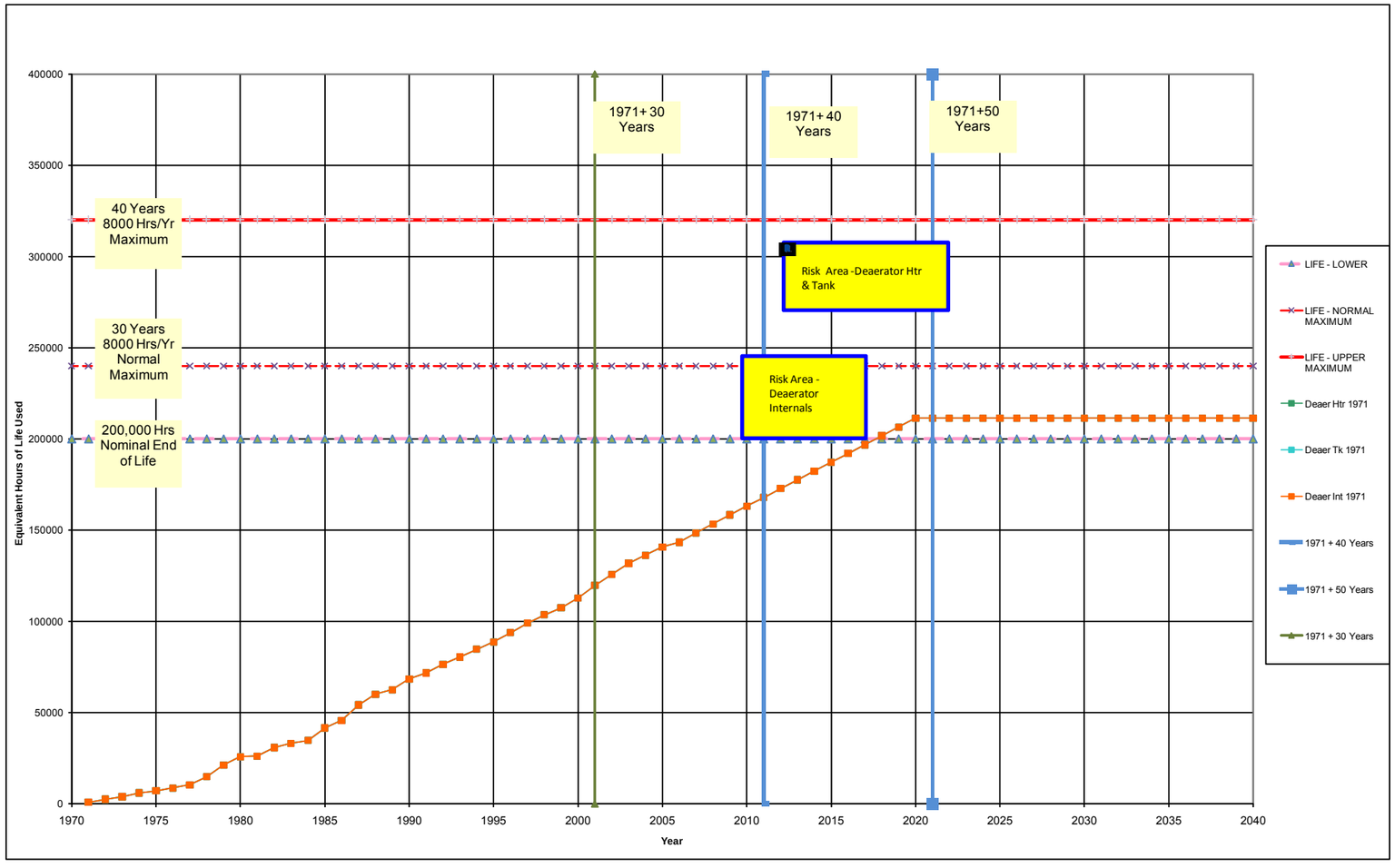



**FIGURE 9-15 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - DEAERATOR**

The curve indicates that the remaining life (RL) of the Unit 2 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. There is however insufficient detailed inspection information of some of the difficult to reach internals to fully assess their condition. A detailed Level 2 inspection in 2013 is recommended to provide information for that assessment.

### 9.2.3.8 Level 2 Inspections – Unit 2 Feedwater System - Deaerator

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-40 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-40 LEVEL 2 INSPECTION – UNIT 2 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 112 | 31 | NDE inspection of the areas that were not inspected is required. | 2013 | 2 | $222 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 113 | 31 | Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 114 | 31 | Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface). | 2013 | 2 | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 115 | 31 | Inspection of the tray stack. | 2013 | 2 | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 116 | 31 | Inspection of the spray valves. | 2013 | | |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | None | 117 | 31 | Inspections for cracking. Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations. | 2013 | 2 | |

### 9.2.3.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | N/A | 109 | 31 | None, pending Level 2 or next inspection. | | |

### 9.2.4 Asset 7992 – Unit 2 Feedwater System - Low Pressure (LP) Feedwater Heat Exchangers

**(Detailed** Technical Assessment in Working Papers, Appendix 24)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7978 #2 Condensate & Feedwater System |
| Sub-Systems: | 7992 #2 Low pressure Feedwater |
| Components: | 7997 #2 L.P. Heater 1 |
| | 7998 #2 L.P. Heater 2 |
| | 8032 #2 LP FW Reserve |
| | 8800 #2 Condensate Extraction System |

#### 9.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 2 contains two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerator.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for the closed feedwater heat exchangers.

Two condensate extraction pumps service Unit 2, driven by 4 kV electric motors. The pumps are original equipment and the motors were installed during the upgrade in 1990. The pumps draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

#### 9.2.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

#### 9.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, tube plugging maps and history were not available. During interviews with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 2.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps or motors. The motors are electrically checked annually and appear to be in reasonable condition for their age. However, the motors are at an age where reliability and failure may be issues in the future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tank have been undertaken recently, due primarily to concerns with enclosed space requirements. Externally, there is some minor surface pitting evident but no significant problems or leaks were noted.

### 9.2.4.4 Condition Assessment

The condition assessment of the Unit 2 feedwater system – LP feedwater heat exchangers (and associated condensate extraction system) components is illustrated below in Table 9-42:

**TABLE 9-42 CONDITION ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 0 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 103 | N/A | See details below. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2011 | No | Yes | 1971 |
| 1296 | 7635 | 7978 | 8800 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 104 | 20 | No issues identified. | 3a | (30) | 10 | 2020 | | | Yes | Yes | 1971 |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #1 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | N/A | 105 | 20 | Pump installed in 1970 and motor in 1990. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1971/1990 |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #1 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | N/A | 106 | 20 | Pump installed in 1970 and motor in 1990. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1971/1990 |
| 1296 | 7635 | 7978 | 7980 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 107 | 31 | See polisher assessment. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2011 | No | Yes | 1971 |
| 1296 | 7635 | 7978 | 7992 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | L P FEEDWATER SYSTEM | N/A | 110 | 26 | Not reviewed in detail, primarily LP heaters. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | N/A | 111 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm | 4 | (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | N/A | 112 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm | 4 | (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | N/A | 113 | 26 | No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections. | 4 | (60) | (20) | 2020 | 2011 | 2011 | Yes | Yes | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 feedwater system - LP feedwater heat exchangers (and associated condensate extraction system) components:

**TABLE 9-43 RECOMMENDED ACTIONS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 144 | 20 | See details below. | | |
| 1296 | 7635 | 7978 | 8800 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 145 | 20 | Spot check likely critical parts of piping and valving – thickness and corrosion. | 2011 | 2 |
| 1296 | 7635 | 7978 | 8800 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 146 | 20 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 7635 | 7978 | 8800 | 7986 | 2 | #2 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | N/A | 147 | 20 | Continue current inspection and maintenance activities. | 2011 | 2 |
| 1296 | 7635 | 7978 | 8800 | 7987 | 2 | #2 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | N/A | 148 | 20 | Continue current inspection and maintenance activities. | 2011 | 2 |
| 1296 | 7635 | 7978 | 7980 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 149 | 21 | No recommended action. | | |
| 1296 | 7635 | 7978 | 7992 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | L P FEEDWATER SYSTEM | N/A | 152 | 24 | Implement ongoing inspections and performance testing based on industry practices. | 20111 | 2 |
| 1296 | 7635 | 7978 | 7992 | 7997 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | N/A | 153 | 24 | Perform Level 2 inspections. | 2011 | 2 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | N/A | 154 | 24 | Perform Level 2 inspections. | 2011 | 2 |
| 1296 | 7635 | 7978 | 7992 | 8032 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | N/A | 155 | 26 | Perform Level 2 inspections on tanks – thickness checks and internals inspections. | 2011 | 3 |
| 1296 | 7635 | 7978 | 7992 | 8032 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | N/A | 156 | 26 | Implement ongoing inspections and performance testing based on industry practices. | 2011 | 2 |

### 9.2.4.6 Risk Assessment

Table 9-44 below illustrates the risk assessment for the Unit 2 feedwater system - LP feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-44 RISK ASSESSMENT – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8800 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | CE Piping/Valves | 129 | 20 | Weld failure, rupture. | 10 | None | 1 | A | Low | 1 | B | Low | Piping leak; short duration shutdown for repair. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | CE Pumps | 130 | 20 | Seal, bearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Current inspection and maintain. |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | 4 kV Condensate Extraction Pump Motor | 131 | 25 | Electrical fault, mechanical fatigue, ops error. | (10) | None | 1 | B | Low | 1 | B | Low | Loss 60% unit generation. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | CE Pumps | 132 | 20 | Seal, nearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Current inspection and maintain. |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | 4 kV Condensate Extraction Pump Motor | 133 | 25 | Electrical fault, mechanical fatigue, ops error. | (10) | None | 1 | B | Low | 1 | B | Low | Loss 60% unit generation. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7978 | 7980 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 134 | | Not addressed. | (5) | None | | | | | | | | |
| 1296 | 7635 | 7978 | 7992 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | L P FEEDWATER SYSTEM | N/A | 137 | 24 | SCC, thermal/ mechanical fatigue. | (10) | Life management program is required | 1 | C | Low | 1 | B | Low | Excessive tube failure event resulting in Turbine water induction. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | N/A | 138 | 24 | SCC, FAC, thermal/ mechanical fatigue, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | N/A | 139 | 24 | SCC, FAC, thermal/mechanical fatigue, corrosion fatigue. | (10) | Brand new Heater can meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | LP Feedwater Reserve Tanks | 140 | 26 | Corrosion, impingement. | (20) | >10 Years. Inspections are required to confirm. | 1 | A | Low | 1 | A | Low | Major Leak, loss condensate. | Inspect and maintain. |

### 9.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 feedwater system - LP feedwater heat exchangers is illustrated below. One curve represents both of the low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

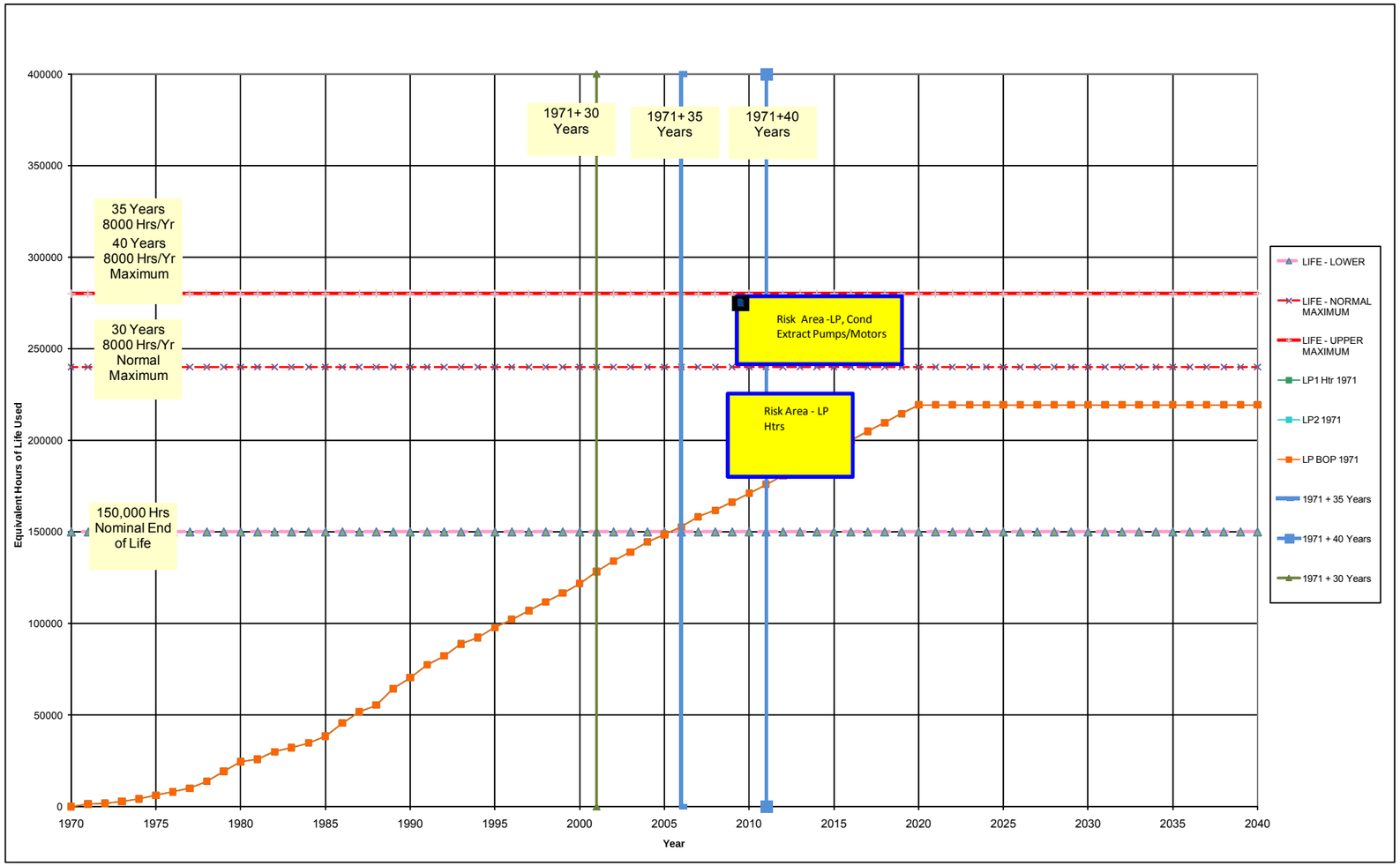



**FIGURE 9-16 LIFE CYCLE CURVE – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

The curve indicates that the remaining life (RL) of the Unit 2 feedwater system - LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 2 condensate extraction pumps and motors is illustrated below. Two curves are used to represent the original equipment pump and the pump motor (upgraded in 1990). The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

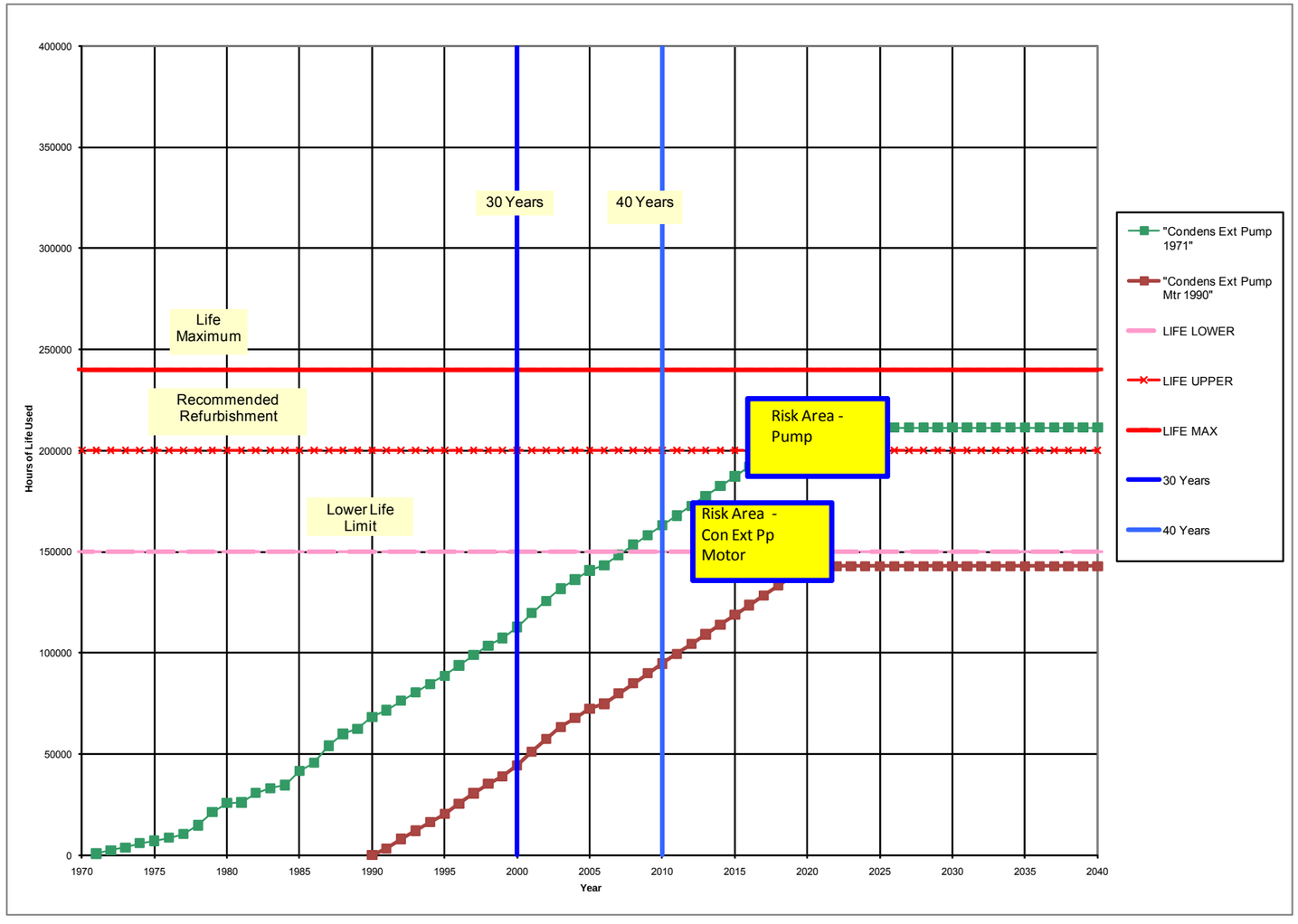



**FIGURE 9-17 LIFE CYCLE CURVE – UNIT 2 CONDENSATE EXTRACTION SYSTEM**

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

### 9.2.4.8 Level 2 Inspections – Unit 2 Feedwater System - LP Feedwater Heat Exchangers

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-45 below, assuming that the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-45 LEVEL 2 INSPECTIONS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 0 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | None | 97 | 24 | No Level 2 required. | | |
| 1296 | 7635 | 7978 | 8800 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | None | 98 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | None | 99 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | None | 100 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | |
| 1296 | 7635 | 7978 | 7980 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | None | 101 | 24 | No Level 2 required. | | |
| 1296 | 7635 | 7978 | 7992 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | L P FEEDWATER SYSTEM | None | 102 | 24 | No Level 2 required. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | None | 103 | 24 | Shell side inspections and channel side for the degradation mechanisms. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | None | 104 | 24 | Assessment of the tube plug map. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | None | 105 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | None | 106 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2011 | $57 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | None | 107 | 24 | Shell side inspections and channel side for the degradation mechanisms. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | None | 108 | 24 | Assessment of the tube plug map. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | None | 109 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2011 | $57 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | None | 110 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2011 | |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | None | 111 | 26 | Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection. | 2011 | $15 |

### 9.2.4.9 Capital Projects

The suggested typical capital enhancements for the low pressure feedwater heat exchangers (and associated condensate extraction system) components include:

**TABLE 9-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FEEDWATER SYSTEM - LP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 0 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 96 | 20 | No capital investment required. | | |
| 1296 | 7635 | 7978 | 8800 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 97 | 20 | No capital investment required. | | |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #2 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND EXTRACTION PUMP NORTH | N/A | 98 | 20 | Replace as required per current inspection and overhaul findings. | 2013 | 3 |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #2 UNIT GENERATION SERVICES | CONDENSATE EXTRACTION SYST | COND.EXTRACTION PUMP SOUTH | N/A | 99 | 20 | Replace as required per current inspection and overhaul findings. | 2013 | 3 |
| 1296 | 7635 | 7978 | 7980 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 100 | | No capital investment required. | | |
| 1296 | 7635 | 7978 | 7992 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | L P FEEDWATER SYSTEM | N/A | 103 | 24 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | N/A | 104 | 26 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | N/A | 105 | 24 | None, pending Level 2 or next inspection. | | |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | N/A | 106 | 24 | None, pending Level 2 or next inspection. | | |

### 9.2.5 Asset 7664 – Unit 2 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7638 - #2 Turbine & Generator |
| Sub-Systems: | 7664 # 2 Turbine & Condenser |
| Components: | 271326 #2 Condenser |
| | 7694 #2 Condenser Air Extraction |

#### 9.2.5.1 Description

The Unit 2 condenser is shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are sized to allow the unit to run at full vacuum with only one pump operating. Each is equipped with a nominally 70 kW, 600 V motor. The condenser also has a stainless steel bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied Foster Wheeler in 1971.

#### 9.2.5.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Next Major Overhaul/Inspection | 2014 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

#### 9.2.5.3 Inspection and Repair History

The Unit 2 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

A recent tubes plug survey completed in 2010 indicated that 3.3% of the condenser tubes are plugged. The 2001 survey indicates that 2.8% of the tubes were plugged at that time. Based on this result, the in-service tube degradation rate of 0.5% over 9 years is very slow. This is also supported by the eddy current testing that was completed in 1998 when 70% of the total condenser tubes were inspected. Results show that 95% of the tubes tested had a wall loss of less than 25%. This is very close to the tube nominal wall thickness and the accuracy of the eddy current testing.

Inspections also confirm that there is no condensate grooving on the tube outside diameter (OD) in the air removing zone of the tube bundle. With the exception of minor wear, the waterboxes and the condenser shell are in good condition.

According to plant staff, the condenser steel piping at the inlet and outlet between the condensers and the underground concrete pipes, have been replaced once but no date was provided. Some patching is evident on some units.

The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified with achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

### 9.2.5.4 Condition Assessment

The condition assessment of the Unit condenser is illustrated below in Table 9-47:

**TABLE 9-47 CONDITION ASSESSMENT – UNIT 2 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 4 | 22 | Good condition | 3a | 200000 (40) | 10 | 2020 | | 2014 | Yes | Yes | 1971 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 5 | 22 | System in good condition. External venting needed. | 10 | 150000 (30) | 5 | 2020 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8884 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | N/A | 6 | 22 | Near end of life. | 10 | 150000 (30) | (2) | 2020 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8891 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | N/A | 7 | 22 | Near end of life. | 10 | 150000 (30) | (2) | 2020 | | 2014 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 7664 | 271326 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 8 | 22 | Condition is very good. 2010 tubes plug survey shows 3.3% of tubes plugged vs 2.8% in 2001. Condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell. | 3a | 300000 (50) | 20 | 2020 | 2011 | 2014 | Yes | Yes | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 condenser:

**TABLE 9-48 RECOMMENDED ACTIONS – UNIT 2 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7664 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 1 | 22 | Develop a ongoing program of monitoring CW inlet/outlet pipe conditions. | 2011 | 2 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 2 | 22 | See details below. | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | N/A | 3 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump. | 2011 | 2 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | N/A | 4 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump. | 2011 | 2 |
| 1296 | 7635 | 7636 | 7664 | 271326 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 5 | 22 | Perform Level 2 inspections on waterboxes for Unit 2 at a practical time. | 2011 | 2 |

### 9.2.5.6 Risk Assessment

Table 9-49 below illustrates the risk assessment for the Unit 2 condenser, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-49 RISK ASSESSMENT – UNIT 2 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 5 | 22 | See details below. | | None | | | | | | | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 6 | 22 | See details below. | 10 | None | | | | | | | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8884 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | Condenser Vacuum Pumps & System | 7 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff Decrease while replaced. | Maintain, refurbish or replace as required. |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8891 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | Condenser Vacuum Pumps & System | 8 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff Decrease while replaced. | Maintain, refurbish or replace as required. |
| 1296 | 7635 | 7636 | 7664 | 271326 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | Condenser | 9 | 22 | Corrosion, erosion. | 20 | None | 2 | B | Low | 2 | A | Low | Major seawater leak to condenser - unit shutdown. Water cleanup. | Inspect and repair. Track history. |

### 9.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 condenser is illustrated below. Only one curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

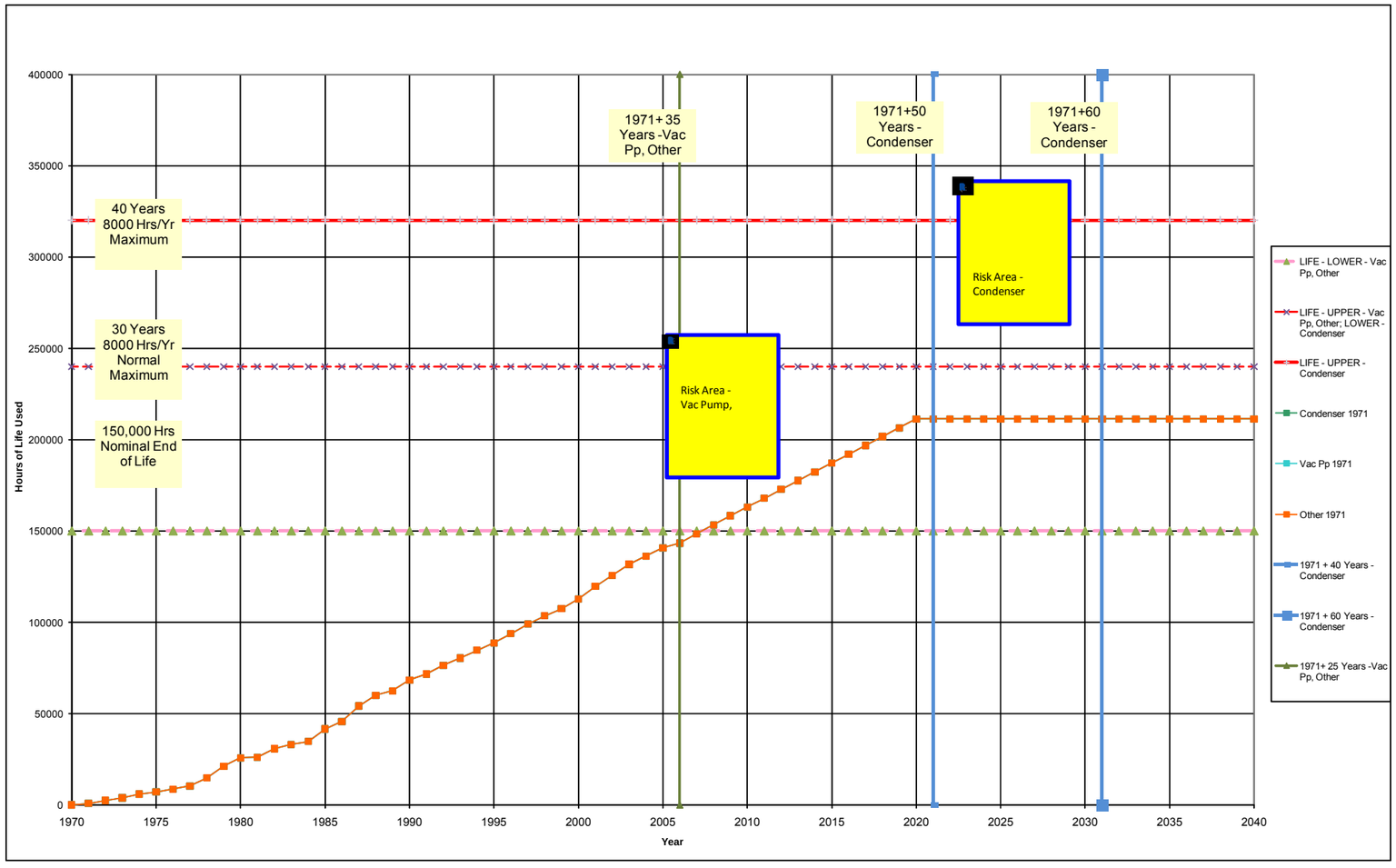



**FIGURE 9-18 LIFE CYCLE CURVE – UNIT 2 CONDENSER**

The curves indicate that the remaining life (RL) of the Unit 2 condenser can easily reach the desired life (DL) 2020 end date for generation. The exception to this, as illustrated by the risk boxes, is the vacuum pumps. These are original equipment, and likely at or near end of life.

### 9.2.5.8 Level 2 Inspections – Unit 2 Condenser

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-50 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-50 LEVEL 2 INSPECTIONS – UNIT 2 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 1 | 22 | NDE spot check inspection of major inlet and outlet pipes. Condensers themselves continue ongoing maintenance and inspection. | 2011 | 2 | $4 |
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 2 | 22 | At next turbine valve overhaul in 2011:<br>- Leak test and update the tubesheet maps for both the waterboxes.<br>- Check the inlet waterboxes for tubes with water erosion at the tube inlets.<br>- Inspect condenser hotwell internal piping and supports for steam and water erosion.<br>- Inspect hotwell drip drains for eroded or missing baffle plates. | 2011 | 2 | $0 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | None | 3 | 22 | No Level 2 required. | | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8884 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | None | 4 | 22 | No Level 2 required. | | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8891 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | None | 5 | 22 | No Level 2 required. | | | |

### 9.2.5.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 5 | 22 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | N/A | 6 | 22 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8884 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | N/A | 7 | 22 | Refurbish/replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8891 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | N/A | 8 | 22 | Refurbish/replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 7635 | 7636 | 7664 | 271326 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | N/A | 9 | 22 | No capital investment required. | | |

### 9.2.6 Asset 8878 – Unit 2 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7786 - # 2 Boiler Plant |
| Sub-Systems: | 7838 - # 2 Boiler Air System |
| | 7890 - # 2 Boiler Gas System |
| | 7912 - # 2 Boiler Fuel Firing |
| | 7913 #2 Bir Heavy Oil System |
| | 7935 #2 Boiler Light Oil |
| Components: | 88781#1 Boiler FD Fan System<br>7843 # 2 Boiler FD Fan East<br>7844 # 2 Boiler FD Fan West<br>7855 # 2 Boiler Steam Air Heater East<br>7856 # 2 Boiler Steam Air Heater West<br>7883 # 2 Boiler Main Air Heater East<br>7884 # 2 Boiler Main Air Heater West |
| | 7916 #2 Boiler Heavy Oil Pump East<br>7917 #2 Boiler Heavy Oil Pump West<br>7920 #2 Boiler Heavy Oil Pump steam, valves and pipe<br>7933 #2 Boiler Heavy Oil Firing<br>8980 #2 Boiler Light Oil Pump East<br>8981 #2 Boiler Light Oil Pump West |
| | 7882 #2 Boiler Air Supply Seal Air<br>7885 #2 Boiler Scanner Air System |

#### 9.2.6.1 Description

The Unit 2 Combustion Engineering (CE) boiler has two 50% duty 4KV AC constant speed motor driven Howden forced draft fans (East/West) which supply the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure that the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the plant DCS system or manually by the operator if required.

In addition, each of the FD fans has a set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

#### 9.2.6.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |
| Max Hours Ops – 1986 to Dec 2009 | 113 |
| Max Hrs - 1986 to Dec 2015 | 142 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 164 |

#### 9.2.6.3 Inspection and Repair History

The FD fans and Ljungstrom air heaters were installed when the unit was constructed in the late 1960's. They are checked annually as part of the boiler inspection program. Generally, all are in reasonable condition considering their age. Issues such as fan component cracking and air heater corrosion are addressed as required. The steam coil air heater was upgraded in 1990 to include a second row of steam coils.

The 2009 Alstom report indicates that Unit 2 West FD fan was inspected and some cracks were repaired on the ductwork and expansion joints. The report did not indicate what work was carried out on the East fan. However, in 2008, a complete evaluation of both fans was conducted by Fan Dynamics out of Cambridge, Ontario. Both FD fans at that time were deemed to be in good condition.

A cold end rebuild of the Unit 2 East and West Ljungstrom air heaters was completed in 2009 as a capital project. The work on the West Ljungstrom air heater as per the Alstom 2009 report indicated that the cold end baskets were reversed to extend the overall life of the baskets. However, these possibly will require changing in a couple of years. Based on experience that Ontario Power Generation had using lower sulphur #6 residual fuel oil (0.7% sulphur), its use at Holyrood should continue to have very positive effects on the air heaters. Corrosion issues and ash deposits (as long as the rotary sootblowers are maintained and used consistently) should not be an issue.

As reported by Alstom in 2008, the combustion steam coils on both the east and the west sides of Unit 2 had a large number of the fins that were bent and possibly creating a higher FD fan differential pressure across these coils. Alstom's recommendation at that time was to fabricate a tool to straighten the fins. However, the final outcome was not documented. In addition, during site visits, AMEC staff was not made aware of any Unit 2 full load limitations caused by either lower than required air flows or excessive FD fan motor amps.

The last outage report completed in 2009 indicated that detailed inspections of this equipment were carried out with minor repairs made to cracks in the ductwork, seals replaced in the air heaters, some gap discrepancies rectified and a recognition that some fins on the combustion coils had bent during operation.

The continued use of the much lower sulphur residual fuel oil (0.7% sulphur) may reduce the corrosion levels noted, especially in the air heaters, and may reduce the maintenance requirements performed by Alstom, depending on a series of operating parameters. The steam coils are pressure tested every year, although no data sheets were reviewed and the inspection dates were not marked on the tubes as had previously been done.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

**Asset 7890 Boilers Flue Gas System, Sootblowers**

The Unit 2 back end flue gas ductwork is original and was installed in 1969. During yearly plant outages, the accessible ductwork has been inspected by Alstom. Reports obtained from the plant indicate that due diligence has been carried out to ensure the structural integrity of the ductwork is maintained and any repairs were being completed at the time of inspection. Structural supports were inspected and all have been identified to be in good condition and will last for the foreseeable future.

With regards to the sootblowing system, minor maintenance is carried out during normal operation. Any major work requires a unit shutdown. Boiler fouling and opacity excursions were observed and changes were implemented to improve the sootblowing sequences.

With the use of a lower sulphur fuel oil, the implementation of an intelligent sootblowing controls system should be considered so that sootblowing is only carried out when needed.

**Asset 7912 Fuel Oil Firing**

Reports at the plant regarding the condition of the light and heavy oil systems were not available. However they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore are not considered to be life limiting.

**Asset 7879 Boiler Air Supply Seal Air and Scanner Air**

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained as noted during AMEC's inspection.

### 9.2.6.4 Condition Assessment

The condition assessment of the Unit 2 FD fans (and system) is illustrated below in Table 9-52:

**TABLE 9-52 CONDITION ASSESSMENT – UNIT 2 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7838 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 77 | 19, 30 | Inspected yearly and repairs completed. Flow induced turbulence in ductwork causing vibration with potential for damage to fD fans and cracks in ductwork. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 7879 | 7885 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR | N/A | 78 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | N/A | 79 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Fan | 80 | 19, 30 | Inspected yearly and repairs completed as required. Good condition. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Fan | 81 | 19, 30 | Inspected yearly and repairs completed as required. Good condition. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Motors | 82 | 25 | Inspected yearly and repairs completed as required. Good condition. | 3a | 200000 (30) | (5) | 2020 | 2011 | | Yes | No | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Motors | 83 | 25 | Inspected yearly and repairs completed as required. Good condition. | 3a | 200000 (30) | (5) | 2020 | 2011 | | Yes | No | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 84 | 19, 30 | Inspected yearly and repairs completed as required. Unit upgraded in 1990. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7855 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 85 | 19, 30 | Inspected yearly and repairs completed as required. Unit upgraded in 1990. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7856 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 86 | 19, 30 | Inspected yearly and repairs completed as required. Unit upgraded in 1990. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1990 |
| 1296 | 7635 | 7786 | 7838 | 8786 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 87 | 19, 30 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7838 | 8786 | 7863 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 88 | 19, 30 | Inspected yearly and repairs completed as required. Cold end rebuild of the east Ljungstrom Air Heater on Unit 2 was completed in 2009. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971/2009 |
| 1296 | 7635 | 7786 | 7890 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 89 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7890 | 7891 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 90 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 91 | 19 | Installed about 1979 with yearly major or minor overhauls. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1979 |
| 1296 | 7635 | 7786 | 7912 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 92 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7912 | 7935 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 93 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1971 |
| 1296 | 7635 | 7786 | 7953 | 0 | 0 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 94 | N/A | Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation. | 4 | 200000 (30) | (5) | 2041 | 2011 | | No | No | 1971 |
| 1296 | 7635 | 7786 | 7787 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 95 | 17 | No recent evaluation. Visual inspection in walkdown indicated no issues except some minor roof leaks. | 3a | 200000 (30) | 20 | 2041 | 2011 | 2011 | Yes | Yes | 1971 |

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

3. The ability of the east and west FD fans to meet a 2020 EOL date may be affected if the planned duct reconfiguration is not undertaken.

### 9.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 FD fans (and system):

**TABLE 9-53 RECOMMENDED ACTIONS – UNIT 2 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7838 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 115 | 19,30 | Continue routine inspection, maintenance and overhaul - evaluate air heater hot end baskets; connect installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes. | 2010 | 1 |
| 1296 | 7635 | 7786 | 7838 | 7879 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR | N/A | 116 | 19,30 | No recommended action. | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | N/A | 117 | 19,30 | Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units in the event of a failure of an existing unit. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 118 | 19,30 | Assess replacement of ductwork with lower vibration, lower noise, more efficient design. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 119 | 19,30 | Assess replacement of ductwork with lower vibration, lower noise, more efficient design. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 120 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 121 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 122 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8786 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 123 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8786 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 124 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7890 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 125 | 19,30 | See details below. | | |
| 1296 | 7635 | 7786 | 7890 | 7891 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 126 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 7635 | 7786 | 7890 | 7904 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 127 | 19 | Update obsolete controls as appropriate. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts. | 2012 | 2 |
| 1296 | 7635 | 7786 | 7890 | 7904 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 128 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7912 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 129 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7912 | 7935 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 130 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7953 | 0 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 131 | 19 | Refurbish and replace unit heaters as required. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7787 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 132 | 17 | Visually inspect difficult to access areas. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7787 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 133 | 30 | Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints. | 2011 | 2 |
| 1296 | 7635 | 7786 | 7787 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 134 | 30 | Evaluate corrosion on the steel structure and hangers in the boilers' penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities. | 2011 | 2 |

### 9.2.6.6 Risk Assessment

Table 9-54 below illustrates the risk assessment for the Unit 2 FD fans (and system), both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-54 RISK ASSESSMENT – UNIT 2 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7838 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SEAL AIR SYSTEM | Scanner & Seal Air | 100 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | D | Low | Worst case - Short duration shutdown for repair. Outage. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 7879 | 7885 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR | Scanner & Seal Air | 101 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | A | Low | Worst case - Short duration shutdown for repair. Outage. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8781 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | N/A | 102 | | See details below. | | None | | | | | | | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Unit #2 LP FD Fan & Motor | 103 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | 4 kV Forced Draft Fan Motor | 104 | 25 | Electrical fault, mechanical fatigue, ops error. | (5) | None | 1 | C | Low | 1 | C | Low | Loss 60% of 1 unit generation and damages. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | 4 kV Forced Draft Fan Motor | 105 | 25 | Electrical fault, mechanical fatigue, ops error. | (5) | None | 1 | C | Low | 1 | C | Low | Loss 60% of 1 unit generation and damages. | Spare and current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Unit #2 LP FD Fan & Motor | 106 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8785 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 107 | | See details below. | | None | | | | | | | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7855 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | Unit #2 Steam Preheat Coils | 108 | 19 | Corrosion, erosion, mechanical distortion. | 10 | None | 1 | A | Low | 1 | B | Low | Short term shutdown for repairs, derated or run at increased impact. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7856 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | Unit #2 Steam Preheat Coils | 109 | 19 | Corrosion, erosion, mechanical distortion. | 10 | None | 1 | A | Low | 1 | B | Low | Short term shutdown for repairs, derated or run at increased impact. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8786 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | APH Ductwork – Gas & Air | 110 | 19 | Corrosion, erosion thinning. | 10 | None | 2 | A | Low | 2 | A | Low | Short duration shutdown for repair/patch. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7838 | 8786 | 7863 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | Unit #2 APH | 111 | 19 | Corrosion, mechanical failure. | 10 | None | 1 | B | Low | 1 | B | Low | 50% shutdown for maintenance and repairs. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7890 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 112 | 19,20 | Leaks into powerhouse. | 10 | None | 3 | B | Medium | 3 | B | Medium | Overpressure. | Maintain and inspect. |
| 1296 | 7635 | 7786 | 7890 | 7891 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 113 | 19,20 | Leaks into powerhouse. | 10 | None | 3 | B | Medium | 3 | B | Medium | Duct split/corrosion. | Maintain and inspect. |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 114 | | Mechanical failure. | 10 | None | 2 | B | Low | 2 | B | Low | Steam leak. Tube erosion. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7912 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | Fuel Feed System | 115 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | C | Low | Derate for short period. Safety. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7912 | 7935 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 116 | | Not addressed. | 10 | None | | | | | | | | |
| 1296 | 7635 | 7786 | 7953 | 0 | 0 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 117 | | Mechanical failure. | (5) | None | 3 | A | Low | 3 | B | Medium | Steam leak. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7787 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 118 | | Mechanical failure | 20 | None | 1 | D | Medium | 1 | D | Low | Structure collapse. | Maintain and inspect. |

### 9.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 FD fans (and system) is illustrated below. Two curves are required to represent the various elements given their different in-service dates and operating history. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

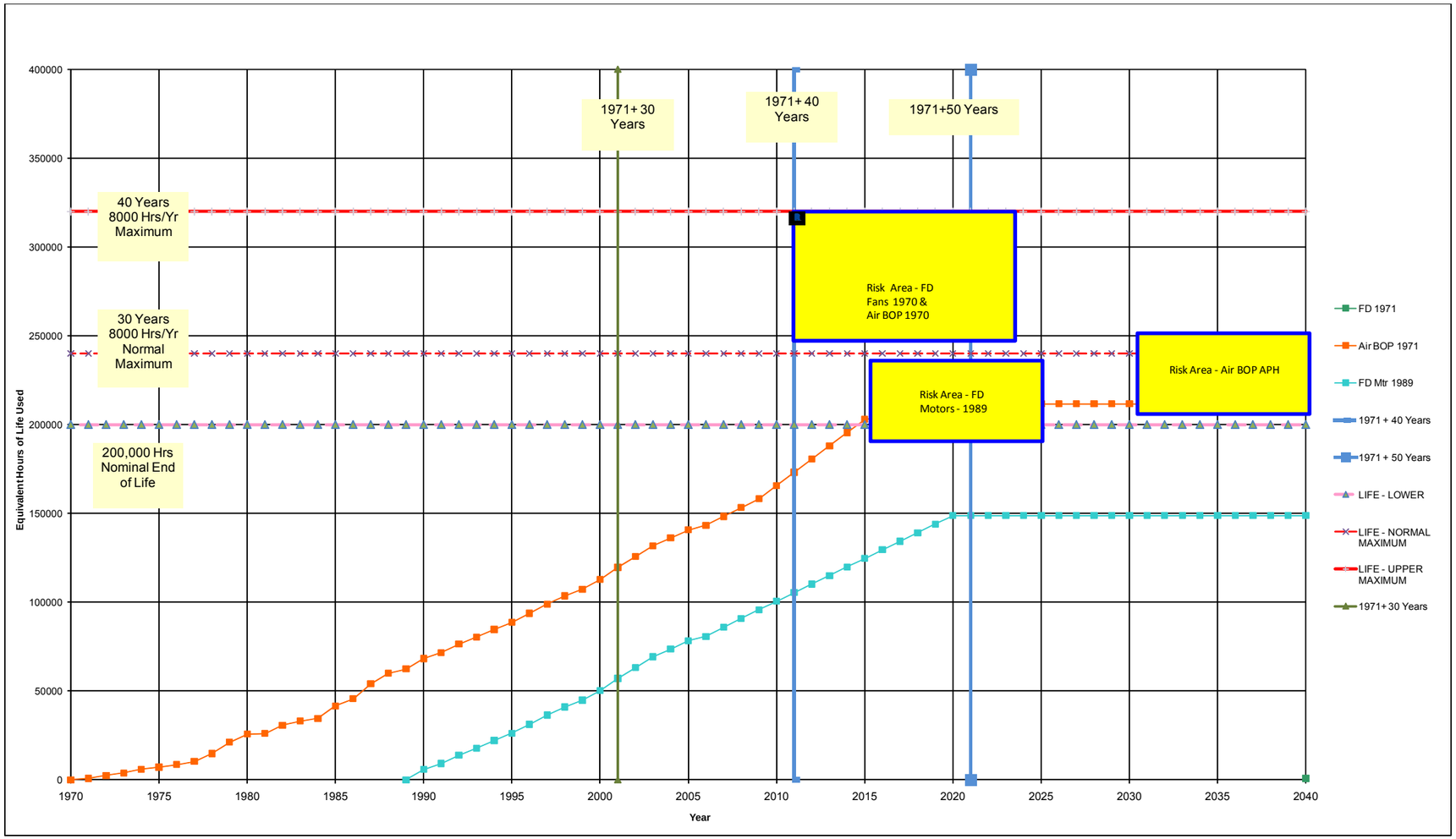



**FIGURE 9-19 LIFE CYCLE CURVE – UNIT 2 FD FANS (AND SYSTEM)**

The curves indicate that the remaining life (RL) of the Unit 2 FD fans (and system) is expected to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

### 9.2.6.8 Level 2 Inspections – Unit 2 FD Fans (and System)

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-55 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-55 LEVEL 2 INSPECTIONS – UNIT 2 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7838 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | None | 78 | 19 | No Level 2 required. | | | |
| 1296 | 7635 | 7786 | 7838 | 7879 | 7885 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR | None | 79 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | None | 80 | 19 | No Level 2 required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | None | 81 | 19 | No Level 2 inspections or testing is required on fan or 4 kV motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken. | | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | None | 82 | 19 | No Level 2 inspections or testing is required on fan or 4 kV motors, provided the current inspection and maintenance program is maintained. Assumes FD turbulence upgrades undertaken. | | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | None | 83 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7855 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | None | 84 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7856 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | None | 85 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8786 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | None | 86 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7838 | 8786 | 7863 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | None | 87 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7890 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | None | 88 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7890 | 7891 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | None | 89 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | None | 90 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7912 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | None | 91 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7912 | 7935 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | None | 92 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 7635 | 7786 | 7953 | 0 | 0 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | None | 93 | N/A | No Level 2 required. | | | |

### 9.2.6.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7838 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 72 | 19 | Upgrade air ducts to reduce vibration, improve efficiency. | 2014 | 1 |
| 1296 | 7635 | 7786 | 7838 | 7879 | 7885 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR | N/A | 73 | | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7838 | 8781 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | N/A | 74 | 19,25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 75 | 19 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 76 | 19 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8785 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 77 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7855 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 78 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7838 | 8785 | 7856 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 79 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7838 | 8786 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 80 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7838 | 8786 | 7863 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 81 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7890 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 82 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7890 | 7891 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 83 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING | N/A | 84 | 19 | FD fan ductwork modifications. | 2011 | 3 |
| 1296 | 7635 | 7786 | 7912 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 85 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7912 | 7935 | 0 | 2 | #2 BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL | N/A | 86 | 19 | No capital investment required. | | |
| 1296 | 7635 | 7786 | 7953 | 0 | 0 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 87 | | New building heating system | 2015-2020 | 2 |
| 1296 | 7635 | 7786 | 7787 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 88 | | No capital investment required. | | |

### 9.2.7 Asset 7900 – Unit 2 Stack and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7786 #2 Boiler Plant |
| Sub-Systems: | 7890 #2 Boiler Gas System |
| Components: | 7900 #2 Boiler Stack<br>271327 #2 Stack Breeching |

#### 9.2.7.1 Description

The Unit 2 stack was constructed in 1969 from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack.

#### 9.2.7.2 History

| Description | Stack Calendar Life | Operating hours/Equiv Op Yrs since Installation to 2009 | Operating hours/Equiv Op Yrs to 2015/2020 |
|---|---|---|---|
| Unit 2 Stack | 44 | 158,000 (19) | 195,000/212,000 (27) |

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |
| | |
| Max Hours Ops – 1986 to Dec 2009 | 113 |
| Max Hrs - 1986 to Dec 2015 | 142 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 164 |

| | |
|---|---|
| Max Hours Ops – 2007/8 to Dec 2009 | 5 |
| Max Hrs – 2007/8 to Dec 2015 | 35 |
| Max Hrs – 2007/8 to Gen End Date Dec 2020 | 59 |

#### 9.2.7.3 Inspection and Repair History

The Unit 2 stack was built in 1966. Since the original construction, the plant has performed regular PM inspections and completed the suggested repairs.

Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seem to suggest that Unit 2 has not been operating below the sulphuric acid dew point. The recent change to a much lower sulphur fuel oil has reduced the acid dew point, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions. Unit 2 carbon steel liner was replaced in 2001.

The inspections also suggest that life should not be an issue for the liners for the next ten years, despite the fact that portions of the liner are in excess of 43 and 33 years of age. The Unit 2 stack has seen approximately 19 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested during the next stack inspection that some NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The Unit 2 stack breeching, referred to as the East and West stack breeching, is connected to the outlet of each air pre-heater and conveys the hot flue gas to the boiler exhaust stack. The original Unit 2 stack breeching was installed in 1970 and had a rectangular cross section that was constructed from carbon steel plate. It was insulated externally with water tight insulation and metal cladding. The original breeching had a life span of approximately twenty years. During operation, there were numerous problems associated with corrosion that led to a complete replacement in 1989.

The existing Unit 2 stack breeching installed in 1989 also has a rectangular cross section that is constructed from carbon steel plate but is insulated internally on the sides and top with borosilicate (glass) block. The breeching sections are also coated externally with a protective film to inhibit corrosion. In addition, the breeching sections also have a silicate concrete floor.

Early into the Unit 2 operation following the upgrade in 1989, problems associated with cracking of the breeching internal insulating liner and concrete floor began develop. The concrete floor began to crack and the insulation blocks began to fall off the breeching, allowing the flue gas to penetrate the breeching plate where it would then cool and form sulphuric acid condensation causing localized corrosion necessitating plate repairs. As a result, the internal insulation liner and breeching plate has required frequent repairs and relatively high maintenance cost during scheduled Unit 2 annual outages.

Hydro completed thickness scanning on Unit 2 stack breeching steel casing in August 2010. The scan indicated that the casing was generally in good condition but localized areas required steel plate

replacement due to corrosion. The current plan is to refurbish the steel casing based on the results of the plate thickness scan, replace the expansion joints and the corroded support structure, and insulate the breeching externally complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. The upgrade will be completed in 2012. Following the upgrade, the stack breeching is expected to be able to make the 2020 generation end date without additional major refurbishment or replacement.

### 9.2.7.4 Condition Assessment

The condition assessment of the Unit 2 stack and breeching is illustrated below in Table 9-57:

**TABLE 9-57 CONDITION ASSESSMENT – UNIT 2 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 98 | 17 | The concrete stacks are in good condition. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Carbon steel liner replaced in 2001. | 3a | (60/30) | 30 | 2041 | 2011 | 2011 | Yes | Yes | 1971/2001 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 271327 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 99 | 17 | Installed in 1990. The current refractory brick lining in the breeching is cracked, causing local corrosion. It is planned to refurbish the breeching and replace the brick refractory with an insulated steel lined duct. | 10 | (30) | 3 | 2020 | 2011 | 2012 | Yes | No | 1990/2012 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 299552 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK LINER | N/A | 100 | 17 | The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Unit 1 carbon steel liner was replaced in 2000 and Unit 2 in 2001. | 3a | 200000 (30) | 10 | 2020 | 2011 | 2012 | Yes | Yes | 2001 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.
3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2012 are not undertaken.
4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

### 9.2.7.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 stack and breeching:

**TABLE 9-58 RECOMMENDED ACTIONS – UNIT 2 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7890 | 7900 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 137 | 17 | See details below. | | |
| 1296 | 7635 | 7786 | 7890 | 7900 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 138 | 17 | Paint stack, at least top portions, within next five years. | 2013 | 2 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 139 | 17 | Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners. | 2012 | 1 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 140 | 17 | Continue to make repairs to deficiencies found in inspection reports. | 2012 | 1 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 141 | 17 | Undertake planned stack breeching refurbishment incuding patching steel liner, installing external insulation, replacing corroded supports structure, and installing ice protection. | 2012 | 1 |

### 9.2.7.6 Risk Assessment

Table 9-59 below illustrates the risk assessment for the Unit 2 stack and breeching, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-59 RISK ASSESSMENT – UNIT 2 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #2 Concrete Shell | 121 | 17 | Structural cracking. | 30 | None | 1 | D | Medium | 1 | D | Medium | Structural failure requiring shutdown. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #2 Stainless Steel Liner | 122 | 17 | Corrosion/failure. | 10 | None | 1 | B | Low | 1 | C | Low | Corrosion causing major leak or failure – major leak requiring repair. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #2 Carbon Steel Liner | 123 | 17 | Corrosion/failure. | (10) | None | 3 | B | Medium | 2 | C | Medium | Corrosion causing major leak or failure – major leak requiring repair. | Current inspection and maintain. |
| 1296 | 7635 | 7786 | 7890 | 7900 | 271327 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | Unit #2 Stack Breeching | 124 | 17 | Corrosion/failure. | 3 | None | 3 | B | High | 2 | B | Low | Corrosion causing major leak or failure – major leak requiring repair. | Repair and maintain. |

### 9.2.7.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 stack and breeching is illustrated below. Four curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

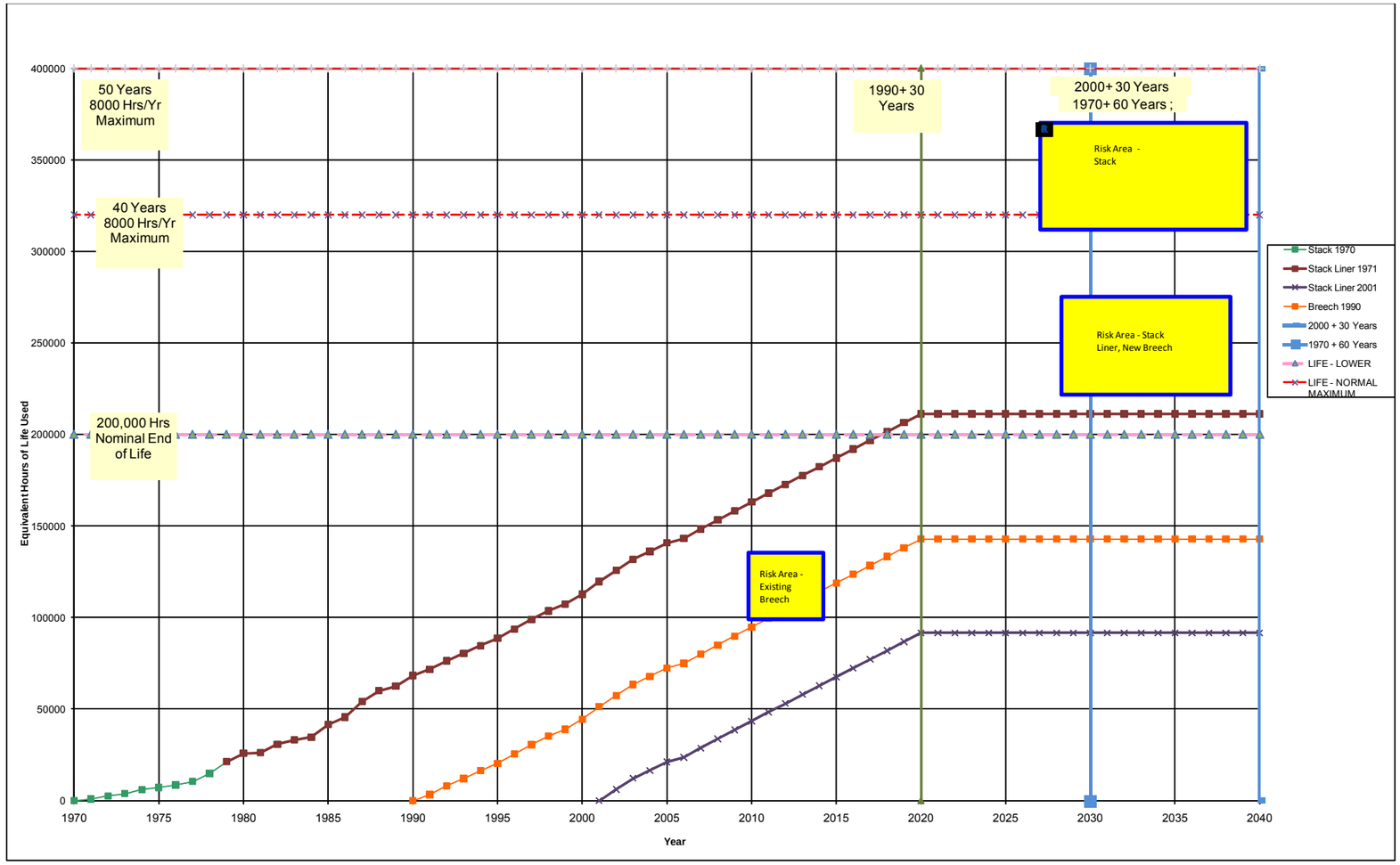



**FIGURE 9-20 LIFE CYCLE CURVE – UNIT 2 STACK AND BREECHING**

The curves indicate that the remaining life (RL) of the Unit 2 stack is able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2040 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of poor design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

### 9.2.7.8 Level 2 Inspections – Unit 2 Stack and Breeching

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-60 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-60 LEVEL 2 INSPECTIONS – UNIT 2 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Stacks | 94 | 17 | No Level 2 inspections. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners. | | | |
| 1296 | 7635 | 7786 | 7890 | 7900 | 271327 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | None | 95 | 17 | No Level 2 required. (Assumes breeching refurbishment undertaken in 2012) | | | |
| 1296 | 7635 | 7786 | 7890 | 7900 | 299552 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK LINER | None | 96 | 17 | No Level 2 required. | | | |

### 9.2.7.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 STACK AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7786 | 7890 | 7900 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 91 | 17 | See details below. | | |
| 1296 | 7635 | 7786 | 7890 | 7900 | 271327 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 92 | 17 | Refurbish stack breeching . | 2012 | 1 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 299552 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK LINER | N/A | 93 | 17 | No capital investment required. | | |

### 9.2.8 Asset 8152 – Unit 2 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed include only those identified as exclusive to the plant steam systems.

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 8152 #2 Electrical System & Controls |
| Sub-Systems: | 8152 #2 Electrical System & Controls |
| Components: | 7677 #2 Turbine Governor System<br>8139 #2 Burner Management<br>309898 #2, Boiler Protection & Control |

#### 9.2.8.1 Description

The following information covers the Unit 2 electrical and control systems within the plant and its associated buildings.

**Asset 7677 Unit 2 Turbine Governor System**

The system is comprised of an electronic speed governor, (GE SpeedTronic Mark V), manufactured by General Electric, and installed in 2003. The governor is complete with protection and monitors speed, metal temperatures, vibration and steam valve positions into the turbine. A human machine interface (HMI) for operator use is provided in the control room.

**Asset 8139 Unit 2 Burner Management**

The present burner management system is comprised of a Modicon PLC and Operator Control (HMI), and was installed in 1995. Field wiring in the bottom of the PLC cabinets is the original as installed in 1969.

The PLC hardware is a Modicon 984 CPU with 800 series I/O and uses Schneider Electric ProWorx software. HMI hardware is a PC with Factory Link Version 6.5 software.

The system controls the operation of the burners, provides start-up and shut-down of the burner, and protection of the fuel and air systems.

In 1995, a major upgrade was completed and the Combustion Engineering Cygnus operator consoles were removed and replaced with a PC based HMI console. At this time the Windows based Factory Link Version 6.5 was installed in the console. During the upgrade the original Modicon 884 processor was replaced with a 984 processor. The original 800 series I/O modules remained and today these are 25 years old.

**Asset 299451 Unit 2 DCS**

The DCS was manufactured by Foxboro and is an Invensys system that was installed in 2004. The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was also installed at that time. The original system was hard-wired, but later updated to a Westinghouse system.

**Asset 309898 Unit 2 Boiler Protection & Control**

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes. The original Bailey system was replaced by Westinghouse WDPF, and in 2004 the system was again updated from the Westinghouse WDPF to the present Foxboro DCS mounted within the original Westinghouse WDPF enclosures.

#### 9.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Controls Upgrade | 2004 |

#### 9.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a support agreement. Upgrades have been and will be carried out as required. Field adjustments and modifications will continue as necessary.

### 9.2.8.4 Condition Assessment

The condition assessment of the Unit 2 E&C control system associated with steam is illustrated below in Table 9-62:

**TABLE 9-62 CONDITION ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | N/A | 179 | 6 | See details below. | | | | | | | | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 180 | 6 | Generator, Transformer and Auxiliary Protection and Metering Panels tests in 2006 were satisfactory. Some ingress of dust and foreign material. Testing is on a 6 year cycle (2012, 2018, 2024, etc.). | 10 | (30) | 10 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 181 | 6 | Breaker overhauls have been carried out in 2006 and 2007, except UB2-2 in 1996 (See Appendix). All 4160V switchgear is applied within ratings. Past normal life - extended by overhauls/maintenance. | 10 | (25) | 5 | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8152 | 7677 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 182 | 6 | Maintenance (PM) and corrective actions (CA) are performed as required. Servos are checked annually due to problems with "dirty" hydraulic lines resulting in blocked pilot strainers. From an electrical and controls point of view, the system is operating well. GE support until 2012-2013 with no guarantee of spares. | 10 | (30) | (10) | 2020 | 2011 | | Yes | No | 1999 |
| 1296 | 7635 | 8152 | 271479 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 183 | 6 | Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time. | 10 | (25) | 5 | 2020 | | | No | No | 1971/2004 |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 184 | 6 | There are age and spares problems with the relaying system. | 4 | (30) | 10 | 2041 | | | Yes | No | 1971 |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 185 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 10+ | 2041 | | | Yes | No | 2004 |
| 1296 | 7635 | 8152 | 8139 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 186 | 6 | Major upgrade in 1995 with HMI operator consoles and processor. Original 800 series I/O modules remained. Minor failures only. Annual maintenance inspections and repairs. | 4 | (25) | 10 | 2020 | | | Yes | Yes | 1995 |
| 1296 | 7635 | 8152 | 309898 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 187 | 6 | In 2004 the system was updated to the Foxboro DCS system in the original WDPF enclosures. | 3a | (20) | 10+ | 2020 | | | Yes | Yes | 2004 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 electrical and control systems (including DCS) associated with steam systems:

**TABLE 9-63 RECOMMENDED ACTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 8138 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 245 | 6 | Test Generator G1, Transformer T1 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 246 | 6 | Include this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2011 | 2 |
| 1296 | 7635 | 8152 | 271479 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 247 | 6 | Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011. | 2011 | 1 |
| 1296 | 7635 | 8152 | 7677 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 248 | 6 | Assess and implement GE migration of the Turbine Governor System Mark V to the Mark Ve system. | 2012 | 2 |
| 1296 | 7635 | 8152 | 8144 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 249 | 6 | Assess removing existing Main Controls control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2011 | 2 |
| 1296 | 7635 | 8152 | 299451 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 250 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 7635 | 8152 | 8139 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 251 | 6 | Transfer the Burner Management system from the PLC system to the DCS as per the 2011 Capital Budget. Remove existing field mounted pressure switches and replace by analog transducers for continuous status monitoring. The Flame Scanners will remain unchanged. | 2011 | 2 |
| 1296 | 7635 | 8152 | 309898 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 252 | 6 | Maintain the Boiler Protection and Control System current through existing Foxboro migration process infinitum. | 2014 | 1 |

### 9.2.8.6 Risk Assessment

Table 9-64 below illustrates the risk assessment for the Unit 2 electrical and control systems (including DCS) associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-64 RISK ASSESSMENT – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 215 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 216 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 217 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Current inspection and maintain. |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 218 | 6 | Electrical fault, ops error. | 10+ | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Maintain. |
| 1296 | 7635 | 8152 | 7677 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 219 | 6 | Electrical/mechanical failure, ops error. | 5 | None | 1 | C-D | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Upgrade governor system. |
| 1296 | 7635 | 8152 | 271479 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | Turbine Supervisory System | 220 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | C | Medium | 3 | C | Medium | Loss 1 unit generation. Damage to unit. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 8139 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 221 | 6 | Electrical fault, mechanical fatigue, ops error. | 10 | None | 3,1 | C | Medium, Low | 1 | C | Low | Loss 1 unit generation. Equipment damage. | Refurbish or replace. |
| 1296 | 7635 | 8152 | 309898 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 222 | 6 | Electrical fault, mechanical fatigue, ops error. | 10+ | None | 1 | 2 | Low | 1 | B | Low | Loss 1 unit generation. Equipment damage. | Maintain. |

### 9.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

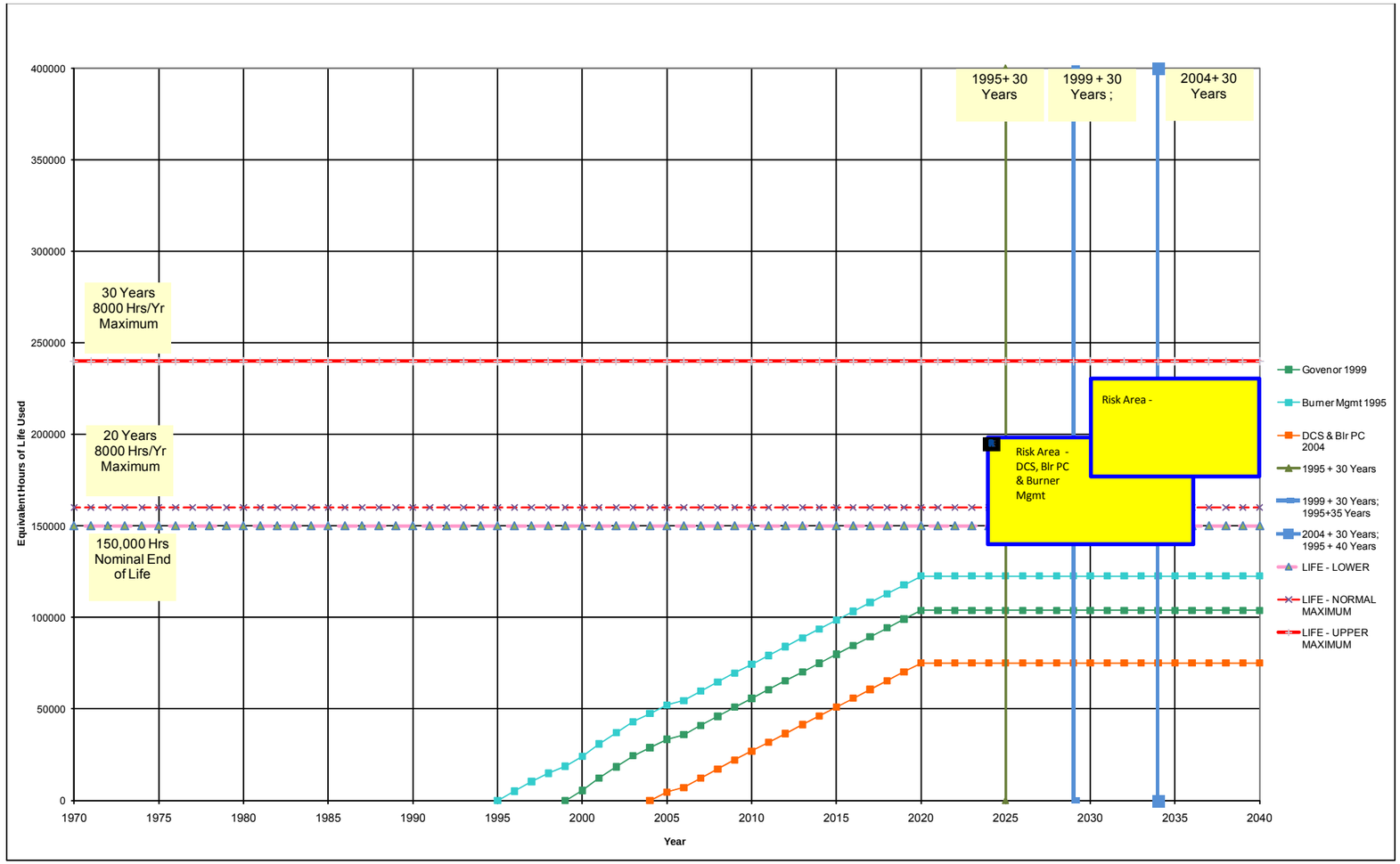



**FIGURE 9-21 LIFE CYCLE CURVE – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 2 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 9.1.3. It is clear that in order to meet the end date for generation service, some of these systems must be replaced or in some cases refurbished.

### 9.2.8.8 Level 2 Inspections – Unit 2 Electrical and Control Systems (including DCS) Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-65 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-65 LEVEL 2 INSPECTIONS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | None | 176 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | None | 177 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | None | 178 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 7677 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | None | 179 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 271479 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | None | 180 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | None | 181 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | None | 182 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 8139 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BURNER MANAGEMENT | BURNER MANAGEMENT | None | 183 | 6 | No Level 2 required. | | | |
| 1296 | 7635 | 8152 | 309898 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | None | 184 | 6 | No Level 2 required. | | | |

### 9.2.8.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 0 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | ELECTRICAL & CONTROLS SYS | N/A | 178 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8138 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | RELAY RM PROTECT & CONTROL | RELAY RM PROTECT & CONTROL | N/A | 179 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 180 | 6 | Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271479 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 181 | 6 | Implement Turbine Supervisory System replacement. | 2013 | 1 |
| 1296 | 7635 | 8152 | 7677 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | N/A | 182 | 6 | Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processors and modernize operator and maintenance stations. Field wiring and devices remain the same. | 2013 | 1 |
| 1296 | 7635 | 8152 | 8144 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | MAIN CONTROLS | MAIN CONTROLS | N/A | 183 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 299451 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 184 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 8139 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 185 | 6 | No capital investment required. | | |
| 1296 | 7635 | 8152 | 309898 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 186 | 6 | No capital investment required. | | |

### 9.2.9 Asset 271317 – Unit 2 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 7638 #2 Turbine & Generator |
| Sub-Systems: | 271317 # 2 Steam turbine |
| Components: | 7638 #2 Main Steam Chest |
| | 7643 #2 HP Turbine |
| | 7652 #2 IP Turbine |
| | 7658 #2 LP Turbine |
| | 7671 #2 Front Standard |

Note: High energy piping and hangers are addressed within the Boiler Section (Section 9.2.1) under heading Boiler Main Steam Lines (Asset Code 7823). The scope is assumed to include piping and hangers up to the steam turbine.

#### 9.2.9.1 Description

The Unit 2 turbine went into service in 1971. It was originally a 150 MW turbine supplied by General Electrical (GE). The original turbine was a 1970 vintage Lynn D3 model. The turbine is rated to operate at a main steam inlet pressure of 13.0 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine rotating speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate pressure (IP) turbine and one double flow low pressure (LP) turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by three journal bearings. The trust bearing and the turning gear are located in the HP front standard.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located at the stator end-shields. In 1989, the unit was upgraded to produce 175 MW by replacing the HP/IP rotor and the HP/IP steam path components including the HP nozzle block. No changes were made to the LP turbine or the auxiliary equipment.

The Unit 2 turbine has an upgraded Mk 5 electro-hydraulic controlled (EHC) governor system with a partial arc steam admission system through the 6 control valves. Unit 2 also has one main stop valve (MSV) with an internal pilot valve to control the run up of the turbine to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the

leakage of process steam along the rotor shaft from the turbine casing. The SSR must be able to respond differently at low and high loads.

The turbine auxiliaries included in this report are:

- The lube oil system;
- The gland steam sealing system, including steam seal regulator;
- The control oil system;
- Steam blow down valve; and
- Power assisted extraction steam non return valves (NRV).

#### 9.2.9.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Units 1 and 2 Upgrade | 1987 |
| Units 1 and 2 Governor Valves | 2003 |
| Units 1 and 2 HP Nozzle Block Replacement | 2007 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Major Overhaul | 2005 |
| Last Valve (Minor) Overhaul | 2002/2007 |
| Next Major Overhaul/Inspection | 2014 |
| Next Valve (Minor) Overhaul | 2011/2017 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

#### 9.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on a six year frequency. As of 2003, the overhauls are scheduled to be done every 9 years with the next overhaul scheduled for 2012.

The turbine valves overhaul frequency of 3 years was not changed. The last valves overhaul was completed in 2007, including a replacement of the HP turbine sections nozzle block. The next valve overhaul is scheduled for 2014.

The Unit 2 SSR is an automated hydraulic control system. Its many moving parts and wear points have resulted in frequent binding and sticking requiring manual intervention during operation. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address the SSR could result in premature deterioration of the steam turbine generator bearings.

The reports indicate that the overhaul work has been done by GE since the year 1999.

**1989 HP/IP Turbine Upgrade**

The upgrade was done to up rate the Unit from 150 MW to 175 MW. The following components were replaced.

- New HP/IP rotor with some stages removed.
- Inner casing steam path change for both the HP and IP turbines.

The upgrade report was not submitted and has not been reviewed. It is assumed that the inner and outer casings of the HP and IP turbines were not replaced. It is also assumed that the casing joint studs were not replaced.

**1999 Major Turbine & Valve Overhaul**

Note: The reports were not complete - pages 39 to 77 are blank. Information on the nozzle partition and turbines is missing. No NDE reports were attached.

- Installed new static exciter;
- Extensive SPE of nozzle block partitions. The partition plates were weld repaired off site;
- SPE of the HP diaphragms. The diaphragm surfaces were polished (NDE reports not available);
- SPE of the IP diaphragms. The affected areas were weld repaired and polished (NDE reports not available);
- Cracks in the LP diaphragm partition plates were weld repaired;
- Replaced all LP inner casing studs. The studs were damaged or over stretched;
- Replaced various turbine valves stems, seats, bushes etc. that were damaged, bent, worn or had run out beyond the allowable limits;
- The CV stems #2, #3 & #4 were bent and replaced. Stem #5 was broken. Attempts had been made to align this stem in 1997;
- Five out of the six crossheads were replaced. All crosshead bushes that had excessive run out and were out of tolerance were replaced:
- Serviced turbine journal bearings, trust bearings, all lube oil pumps and turning gear, etc. Flushed the lube oil system; and.
- The unit had to be shut down 5 times after startup to correct bearing vibration, EHC fluid leaks in front standard and the control valve #1 problems (foreign object in steam chest).

**2002 Turbine Valve Overhaul**

No NDE reports were attached. The valve may **not** have been NDE inspected.

- MSV stem was bent and replaced. There was a crack in the seat seal weld which was weld repaired. Details of weld procedure were not provided. If a weld repair was not done per the approve weld procedure, the crack could reappear or new cracks may start in the heat effect zone of the weld;
- Four out of the six CV stems were replaced. Stem #2 had high run out. Stem #3 was cut to allow valve disassembly. Stems #4 and #5 were worn out and bent. Various valve bushes were replaced;

- The spigots fit on all CV to steam chest were found to be loose. An alignment jig was fabricated and stem #3 was aligned. Two dowel pins were installed in valve stand to maintain the stem alignment. Since other CVs were already installed, they were not aligned per valve #3; and
- All #3 CV bushes were replaced. The wear tear in this valve was to be checked during the next 2005 outage to see if there is any improvement. If successful, this alignment was to be applied to all the CVs. It appears this fix did not work or was not followed through.

**2005 Turbine Major Overhaul**

Note that many NDE reports did not identify clearly what component was inspected.

- The MSV stem was bent and replaced;
- The CV stems #2, #3, and #5 had high run out and were replaced. The CV #6 was replaced due to erosion and wear. The four cross heads #2, #3, #4 and #6 were replaced due to wear and high run out. All cross head bushes were replaced. Many other stems bushes were replaced because of excessive clearances;
- The "stands" for CV #3 and #5 were sent out to have the "spigot fit between the valve stand and the crosshead guide bushing cap machined to align the crosshead guide bushes with the valve stem bushing". There was no mention of the 2002 CV #3 fix and if it worked. See 2002 overhaul report above;
- 2 cracks in seat seal weld of the left RSV were removed and weld repaired. If the weld repair was not done per the approve weld procedure, crack will reappear or new cracks may start in the heat effect zone of the weld;
- The nozzle block was sent off site to restore axial clearance of the block to the design value by weld build up. The repair work also included the weld repairs of the partition plates, spill strip weld built up & machining and austenitic filler piece modification. Information is missing on the condition and what partition plates were repaired. This information would have helped to check if FOD contributed to the failure of the same partition plate in 2007;
- The HP inner shell ring was sent off site for machining. A crack was found growing from the old crack stopper hole. A new crack stopper hole was drilled and the crack blended out. More details and pictures are required to analyze the risk for failure;
- There was a significant SPE to the HP diaphragms. Stage 2 to 6 diaphragms were weld repaired at site using the Inconel and polished;
- There was some SPE of the IP diaphragms. The damaged areas were weld repaired using the Inconel and polished;
- A crack in the LP upper half outer casing was removed by grinding;
- Various LP hood support struts had cracks that were removed and weld repaired;
- The LP turbine two last stage diaphragm partitions had water erosion and were repaired;
- Serviced and cleaned lube oil coolers, pumps, vapour extractor and flushed the lube oil lines;
- Mark 5 control cabinets were installed. (The report did not specify if a new teeth wheel and speed pickups were install for over speed protection); and
- The report did not specify if the lube oil system full flow in-line filter cubical was hooked up during this outage or earlier 2002 outage.

**2007 Forced Outage**

On May 13, 2007, a marked change in unit vibration was noted. However, the unit was kept on line until a control valve malfunctioned and caused a forced outage. The stuck CV #5 was investigated and a partition plate was found wedged between the valve plug and the seat. A bore scope inspection confirmed two nozzle partition plates had liberated in the valve #5 segment. After opening the HP turbine, extensive damage was found in the HP steam path.

Most repair work was limited to HP turbine only. The 2008 valve overhaul work was brought forward and included in the 2007 forced outage, except for the overhauls of the extraction steam NRVs air actuators. The following work was completed during the forced outage:

- Installed a new HP nozzle block;
- Replaced the first three stage blades of the HP turbine. Prior to blade installation, the wheel dove tails were inspected and found acceptable;
- There was some minor foreign object damage (FOD) on the remaining 4 to 9 stage blades. The blades were NDE inspected and no cracks were found. The blades were straightened and polished. GE has recommended replacing the stage 4 to 9 blades earlier than later;
- Repaired all HP diaphragms off site. Stage 2 to 6 diaphragms underwent major repairs. Weld repair was done to stages 2, 3, 4 and 6 partition plates using 410 SS filler wire. Inconel was used on stage 5 partition plates;
- GE had recommended a major repair on 7th stage partitions but these were polished per NLH direction. The 8th and 9th stage partitions underwent minor trimming, straightening and Inconel repair;
- New spill strip seals were installed on all HP diaphragms;
- The IP turbine first RH stage (stage 11) blades had considerable solid particle erosion (SPE) and foreign object damage (FOD). The blades were NDE inspected and no cracks were found. Due to the blades replacement cost and delivery, the blades were not replaced. Polishing and cold straightening was done as required;
- IP 12th stage blades had SPE on some trailing edges. The edges were straightened and the damage blended out;
- IP 14th stage blades had abnormal impact damage. It is heavy and localized to a few blades. Minor repair was done;
- The IP 14th, 15th and 16th stage diaphragm horizontal joints and the support keyways were damaged due to an error during the last reassembly and alignment of the diaphragms. The keyways were repaired at site using Inconel and the joint was sanded and stone flat;
- GE has recommended that during the next outage, the three diaphragms be sent off site for repair to the support block keyways and the horizontal joint;
- The MSV stem was bent and replaced;
- The stem of the CV #5 was broken that had forced the unit outage. The stem breakage was caused by a portion of a nozzle partition plate wedged between the seat and the plug;
- The CV #3 stem was bent. Stem #6 was cut out. Both stems were replaced. GE recommended Inconel stems for future stem replacement;
- The CV #3, #4 and #5 stem lower bushings were found over sized. The bushes were replaced;
- The crosshead of the CV #5 were replaced as it was heavily worn and 0.10" out of round (this is very high). The crosshead brass bushings of all the valves, except CV#6, were found to be out of round and significantly over tolerance and replaced;

- There was a crack in the #102 extraction steam NRV. The crack was repaired. The valve has had weld repairs many times and may have internal casting defects. GE has recommended that the valve body be replaced; and
- Bearing #1 liner was replaced. The lube oil and hydraulic oil systems were flushed.

After the overhaul and the mechanical over speed test, the MSV was reading open when it should have been closed. The MSV was disassembled and 2.3 kg (5 lbs) of debris was found in the valve. The fine mesh screen was completely covered and plugged. Smaller particles had passed through the screen. The screen was cleaned. The control servo was replaced as a part of the valve problem investigation. The rivets damaged by the debris were replaced. No boroscope inspection was done to record the damage to the new nozzle block.

### 9.2.9.4 Condition Assessment

The condition assessment of the Unit 2 steam turbine is illustrated below in Table 9-67:

**TABLE 9-67 CONDITION ASSESSMENT – UNIT 2 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 34 | 18 | See details below. | | | | | | | | | |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 35 | 18 | Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and valves are original equipment. | 4 | 200000 (30) | (2) | 2020 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 36 | 18 | Nozzle block and the first three HP stage blades were replaced in 2007 forced outage. Extensive solid particle erosion (SPE) and foreign object damage (FOD). Turbine casing, high temperature studs and valves are original equipment. HP rotor and HP steam paths that see the high pressure and temperature service replaced in 1989. Lot of studs with excessive over projection in the HP inner and outer casings. | 4 | 200000 (30) | (10) | 2020 | | 2014 | Yes | No | 1971/1988/ 2007 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 37 | 18 | Many control valve stem failures and the wear/tear of various stem bushes. High temperature studs and valves are original equipment. Generally valves in good shape. | 4 | 200000 (30) | (2) | 2020 | 2011 | 2011 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 38 | 18 | Extensive solid particle erosion (SPE) or foreign object damage (FOD). The first reheat stage blades have significant impact damage. Generally turbine and valves in good shape. Turbine casing, high temperature studs and valves are original equipment. IP rotor and IP steam paths that see the high pressure and temperature service replaced in 1989. | 4 | 200000 (30) | (10+) | 2020 | | 2014 | Yes | No | 1971/1988 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | N/A | 39 | 18 | Generally turbine in good shape. LP rotor, LP turbine casings are the original equipment. | 3a | 200000 (40) | 10+ | 2020 | | 2014 | Yes | Yes | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7671 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE FRONT STANDARD | N/A | 40 | 18 | High temperature studs and valves are original equipment. Generally valves in good shape. | 4 | (30) | 10 | 2020 | 2011 | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 41 | 18 | Original equipment. | 4 | (30) | 10 | 2020 | | 2014 | Yes | Yes | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 42 | 18 | Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings. | 10 | (30) | (2) | 2020 | | 2012 | Yes | No | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7690 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 43 | 18 | Original equipment. | 4 | (30) | 10 | 2020 | | 2014 | Yes | Yes | 1971 |
| 1296 | 7635 | 7636 | 271317 | 7692 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | N/A | 44 | 18 | Original equipment. Problems with chain system. | 4 | (30) | (2) | 2020 | 2011 | 2011 | Yes | No | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.
3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2012

### 9.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 steam turbine:

**TABLE 9-68 RECOMMENDED ACTIONS – UNIT 2 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 44 | 18 | During upcoming 2011 minor overhauls and the 2014 major overhaul (and every valve outage):<br>1. Perform a bore scope inspection of the nozzle block partitions to check for cracks at the interface weld between the partition plates and the retaining rings. Check for cracks that may have propagated into the partition plate material. Extra attention should be given to the partitions plates in the control valves 2 and 5 segments.<br>2. Perform an inspection (record and pictures)of the SPE/FOD damage due to the 2007 debris in the MSV. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 45 | 18 | Inspect and record (take pictures) during the upcoming 2014 major overhaul, the SPE/FOD damage due to the 2007 debris in the MSV. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 46 | 18 | Replace only studs that have mechanical damage, thread deformation or thread wear, irrespective of the temperature service or stud location. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 47 | 18 | Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out. | 2010 | 1 |
| 1296 | 7635 | 7636 | 271317 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 48 | 18 | Evaluate and resolve the many control valve stem failures. The change of the stem material to Inconel will not solve this problem. Contact Bill Dumbleton (former Saskpower - turbtech@telusnet.net). | 2010 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7638 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 49 | 18 | Estimate MSV/CV/RSV and ICV AR283 casing studs close to the nozzle block studs that operate above 850 °F - see HP a IP inner casings. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the majority of the studs in a valve body are being replaced due to mechanical wear or tear damage. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7638 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 50 | 18 | Work with vendor to identify and resolve key valve issues. Undertake thorough inspection for cracks in both the RH/LH main steam stop valve. Re-inspect all repair welds for cracks in the MSV seat seal weld and/or cracks in the anti-swirl dam (may have been weld repaired during the last few outages). Repair where required using a temper bead weld procedure. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7638 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 51 | 18 | Replace the extraction steam NRV # 102 valve body. The valve may have various internal imperfections and over time various cracks at different locations will reappear or the valve may fail.<br>Increase Extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 52 | 18 | In 2011 minor overhauls and the 2014 major overhaul, carry out the following work and inspections:<br>1. Replace the HP diaphragm and spill strip if NL Hydro wants to improve the unit efficiency.<br>2. Inspect the first three dressed up HP stage blade surfaces for cracks, wear and tear. Blade replacement is not recommended for relatively minor efficiency loss if unit is operated above 75% MCR.<br>3. Inspect repaired HP diaphragm partition trailing edges (built up using Inconel 82 TIG wire) to check if the Inconel is washing or wearing out. Repair minor damage using Inconel 82, but for extensive damage be prepared to repair the partition off site with 410SS filler material (including stress relief and post weld heat treatment).<br>4. Check past 410 SS and Inconel repairs in HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and Inconel repairs. Repair and dress damage where required.<br>5. Check condition of 7th stage diaphragm for further damage since 2007 (damage not repaired in 2007).<br>6. Re-inspect dressed up HP 2nd and 3rd stage blades (from 2007 nozzle partition plate failure). | 2011 | 1 |

Table 9-68 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 7643 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 53 | 18 | Estimate HP inner casing studs close to the nozzle block studs that operate above 650 °F that may have reached or are close to the end of their predicted creep life (GE to identify studs that operate close to and above 850 °F and supply their engineering article on their recommended practice for the high temperature stud replacement). Replace studs close to the end of their creep life. Typically per past GE stud creep life evaluation, turbine half casing studs have a life of around 250,000 to 300,00 hrs. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 54 | 18 | Inspect HP inner casing stud #101 (found broken in 2005), if stud is available - did stud fail due to creep and verify the stud material. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 55 | 18 | Turn in the HP outer and inner casing studs that have a projection over the allowable limits. Machine seized studs that do not move. Clean, re-tape holes and re-install studs that are not damaged. Asses stud supply options - OEM or other. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 56 | 18 | Estimate MSV/CV/RSV and ICV casing studs close to the nozzle block studs that operate above 850 °F - see HP & IP inner casings. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the majority of the studs in a valve body are being replaced due to mechanical wear or tear damage. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 57 | 18 | Re-inspect all cracks in the RSV seat seal weld and/or cracks in the anti-swirl dam. Repair where required using a temper bead weld procedure. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 58 | 18 | Repair the IP 14th, 15th and 16th stage diaphragm horizontal joints and the support keyways found damaged due to an error during the 2005 reassembly. Send these three diaphragms off site for repair and repair the partition plates of these diaphragms using the 410 SS material. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 59 | 18 | The first RH stage blades have considerable SPE damage from particles carry over from the boiler reheater. GE has recommended that blades are replaced. Since there are no pictures, the condition or the risk of blade failure can not be assessed. Re-inspect the blades and a strategy must be in place to:<br>1. Replace the blades if the blade surface has worn down to the level that there is a danger of blade failure. Little impact damage will not fail the blade but will have impact on the IP turbine efficiency.<br>2. Replace blades after 2014 if they will not last for another 5 years of operation (new row blades could cost $300,000 installed). | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 60 | 18 | The IP 14th stage blades have localized damage on a few blades. The damage was blended out. GE has recommended the blades be replaced. Per pictures, the damage is not bad. Inspect blades for cracks and have a strategy in place to replace only the blades that have the damage ($0 estimated as most likely the blades will not require replacement). | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 61 | 18 | Inspect and have a plan in place to do a permanent repair for steam cutting of the LP inner horizontal joint around 5th stage both flow. | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | N/A | 62 | 18 | Do a borescope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after the seasonal operation. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | N/A | 63 | 18 | In 2011 minor overhauls and the 2014 major overhaul, carry out the following work and inspections:<br>1. Inspect and braze broken tie wires on any LP blades to ensure that the designed blade damping condition is maintained.<br>2. Inspect, where possible, L0 and L-1 blade root and wheel steeple surfaces. Repair and replace blade as required.<br>3. Inspect L0 and L-1 blades for water erosion and report. Past reports did not comment on the condition of the blades. Take pictures of the blade surfaces with water wear. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7671 | 2 | #2 TURBINE | TURBINE | TURBINE FRONT STANDARD | N/A | 64 | 18 | Undertake normal major inspection checks. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7686 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 65 | 18 | No specific recommended actions beyond normal major overhaul work. | 2014 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7686 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal regulator | 66 | 18 | Replace steam seal regulator. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7690 | 2 | #2 TURBINE | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 67 | 18 | No specific recommended actions beyond normal major overhaul work. | 2011 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7692 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | N/A | 68 | 18 | No specific recommended actions beyond normal major overhaul work. | 2014 | 1 |

### 9.2.9.6 Risk Assessment

Table 9-69 below illustrates the risk assessment for the Unit 2 steam turbine, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-69 RISK ASSESSMENT – UNIT 2 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Risk Level | SAFETY RISK ASSESSMENT MODEL Likeli-hood | Conse-quence | Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 40 | | See details below. | | None | | | | | | | | |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 41 | 4 | Valve mechanical failure. | (2) | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure. | Inspect and maintain. Identify long term solution. |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | High Pressure Turbine Diaphragms, Nozzle Partition Plates and Turbine Blades | 42 | 18 | Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD). | 10 | None | 2 | B | Low | 2 | A | Low | Turbine lost generation, efficiency, capacity. Safety. | New nozzle block and some partitions replaced in 2009. Inspect and maintain. Eliminate FOD. |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 43 | 18 | Valve mechanical failure. | (2) | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure. | Inspect and maintain. Identify long term solution. |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | Intermediate Pressure Turbine Diaphragms, and First Stage Turbine Blades | 44 | 18 | Mechanical failure - SPE and erosion from Foreign Object Damage (FOD). | 5 | None | 2 | B | Low | 2 | A | Low | Turbine lost generation, efficiency, capacity. Safety. | The diaphragms haves been repaired. The blades cannot be repaired. No current condition assessment of the blades. Check condition of the first stage RH blades in 2012 overhaul. Eliminate SP and FOD. |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | Low Pressure (LP) Turbine | 45 | 18 | Chemical/Mechanical failure - LP monoblock integral discs - SCC failure. | 10 | None | 1 | B | Low | 1 | B | Low | Turbine lost generation, efficiency, capacity. | Manage the condensate and feedwater chemistry within the ASME guidelines. |
| 1296 | 7635 | 7636 | 271317 | 7671 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE FRONT STANDARD | N/A | 46 | 18 | Not addressed in detail. Mechanical failure. | 10 | None | 1 | C | Medium | 1 | C | Low | Turbine shutdown, overspeed failure. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 47 | | Not addressed. Mechanical sealing failure. | 10 | None | 1 | C | Low | 1 | C | Low | Steam leak. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 48 | | Mechanical sealing failure. Obsolete. | (2) | None | 3 | C | Medium | 3 | C | medium | Turbine shutdown. Bearing failure. Safety risk under turbine. | Replace. |
| 1296 | 7635 | 7636 | 271317 | 7690 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 49 | | Not addressed in detail. Mechanical failure. | 10 | None | 2 | A | Low | 1 | A | Low | Slow start up. | Inspect and maintain. |
| 1296 | 7635 | 7636 | 271317 | 7692 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | N/A | 50 | | Not addressed in detail. Mechanical failure. | 10 | None | 3 | B | Medium | 3 | A | Low | Turbine bowing without turning gear on shutdown. | Inspect and maintain. |

### 9.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 steam turbine is illustrated below. The two curves represent either the original equipment or that upgraded in 1988 when the turbine was uprated. The unit is due to undergo a major overhaul in 2014. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

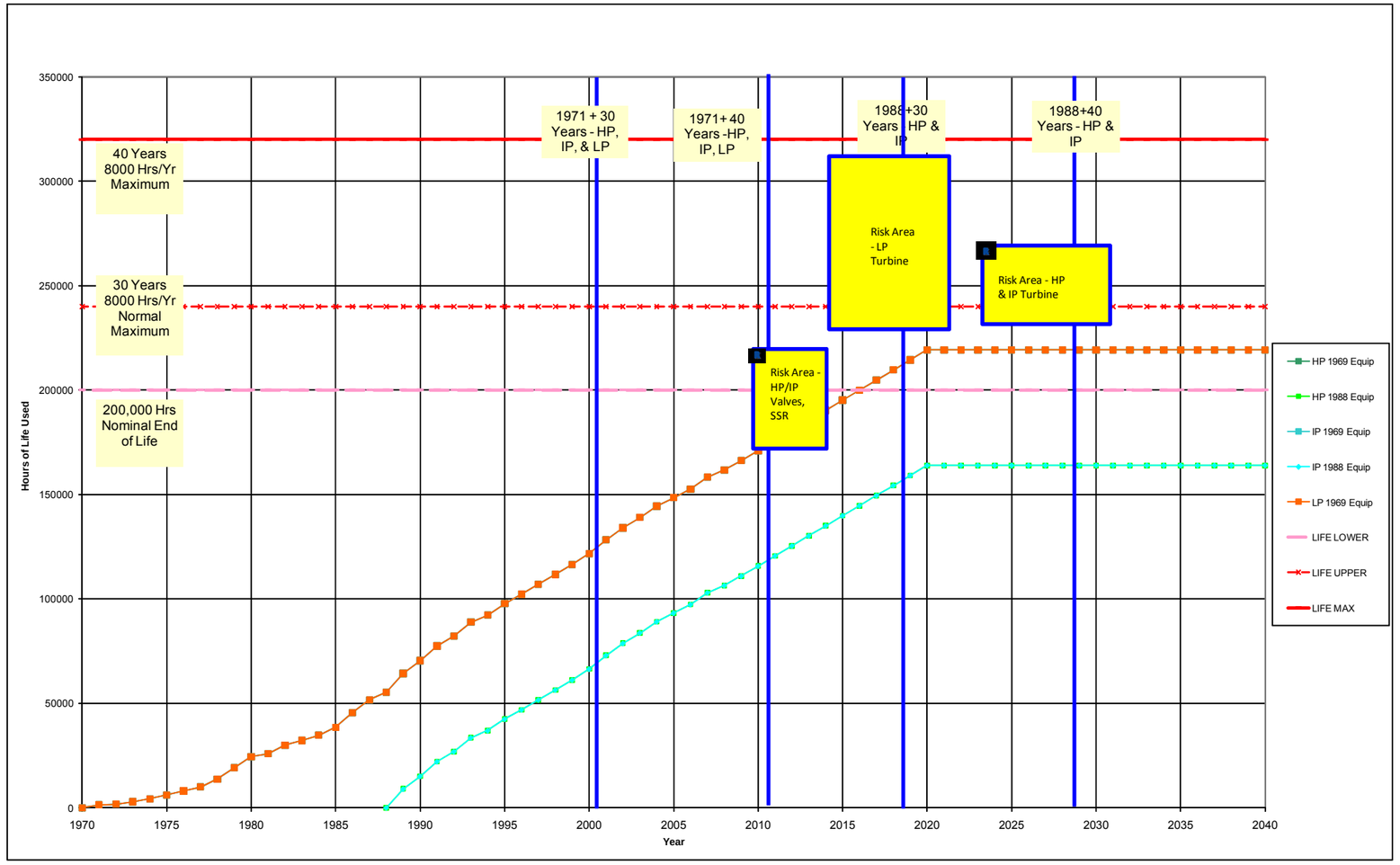



**FIGURE 9-22 LIFE CYCLE CURVE – UNIT 2 STEAM TURBINE**

The curves indicate that the remaining life (RL) of the various elements of the Unit 2 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2014) or to the desired End of Life (EOL) date of 2020. In fact, the 2020 end date should be readily achievable. Hence, no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2014 overhaul to confirm the ability to meet the 2020 EOL date. The exception to that are the HP and IP valves which continue to have reliability and life issues, the steam seal regulator, as well potentially as high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

### 9.2.9.8 Level 2 Inspections – Unit 2 Steam Turbine

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-70 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-70 LEVEL 2 INSPECTIONS – UNIT 2 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | None | 24 | 18 | No Level 2 inspections. Actions identified fall under the norms of the overhaul scopes. | 2014 | 1 | $2,451 |
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | None | 25 | 18 | Nozzle Block Partitions Borescope: During every valve outage, do a bore scope inspection of the nozzle block partitions to check for cracks at the interface weld between the partition plates and the retaining rings. Check for cracks that may have propagated into the partition plate material. Extra attention should be given to the partitions plates in the control valves 2 and 5 segments. Also, inspect and record (take pictures) the SPE/FOD damage due to the 2007 debris in the MSV. | 2014 | 1 | |
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | None | 26 | 18 | No Level 2 | | | |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #1 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | None | 27 | 18 | Identify and asses studs that operate above 850 ◦F may have reached or are close to the end of their predicted creep life (HP MSV studs). | 2011 | 1 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | None | 28 | 18 | Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life ( HP inner casing studs close to the nozzle block). | 2011 | 1 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | None | 29 | 18 | Identify and asses studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs). | 2011 | 1 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | None | 30 | 18 | Identify and assess those studs that operate above 850 °F may have reached or are close to the end of their predicted creep life (IP inner casing studs). | 2011 | 1 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | None | 31 | 18 | LP L0 blades Boroscope: If possible, do boroscope inspection of LP L0 blades once a year through the LP turbine inspection door after the unit is shut down after every seasonal operation. | 2011 | 1 | $6 |
| 1296 | 7635 | 7636 | 271317 | 7671 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE FRONT STANDARD | None | 32 | 18 | No Level 2 required - included in steam turbine overhaul. | 2011 | | |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | None | 33 | 18 | No Level 2 required - included in steam turbine overhaul. | 2011 | | |
| 1296 | 7635 | 7636 | 271317 | 7690 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE PRE-WARMING SYSTEM | None | 34 | 18 | No Level 2 required - included in steam turbine overhaul. | 2011 | | |
| 1296 | 7635 | 7636 | 271317 | 7692 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | None | 35 | 18 | No Level 2 required - included in steam turbine overhaul. | 2011 | | |

### 9.2.9.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | N/A | 32 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 33 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | N/A | 34 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 35 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | N/A | 36 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | N/A | 37 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7671 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE FRONT STANDARD | N/A | 38 | 18 | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 39 | 18 | Replace the steam seal regulator. | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7690 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 40 | | No capital investment required. | | |
| 1296 | 7635 | 7636 | 271317 | 7692 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | N/A | 41 | 18 | Refurbish chain and mechanism. | 2014 | 1 |

### 9.2.10 Asset 271486 – Unit 2 Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

| | |
|---|---|
| Unit #: | 2 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8093 #2 Unit Generation Services |
| Sub-Systems: | 271486 #2 CW System |
| Components: | 8097 #2 CW Travelling Screens East |
| | 8098 #2 CW Travelling Screens West |
| | 8106 #2 CW Pump East |
| | 8107 #2 CW Pump West |
| | 8095 #2 CW Intake |
| | 8120 #2 CW Discharge to Outfall |

#### 9.2.10.1 Description

The circulating water (CW) systems servicing Unit 2 consist of two 50% CW vertical turbine pumps driven by 4 kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

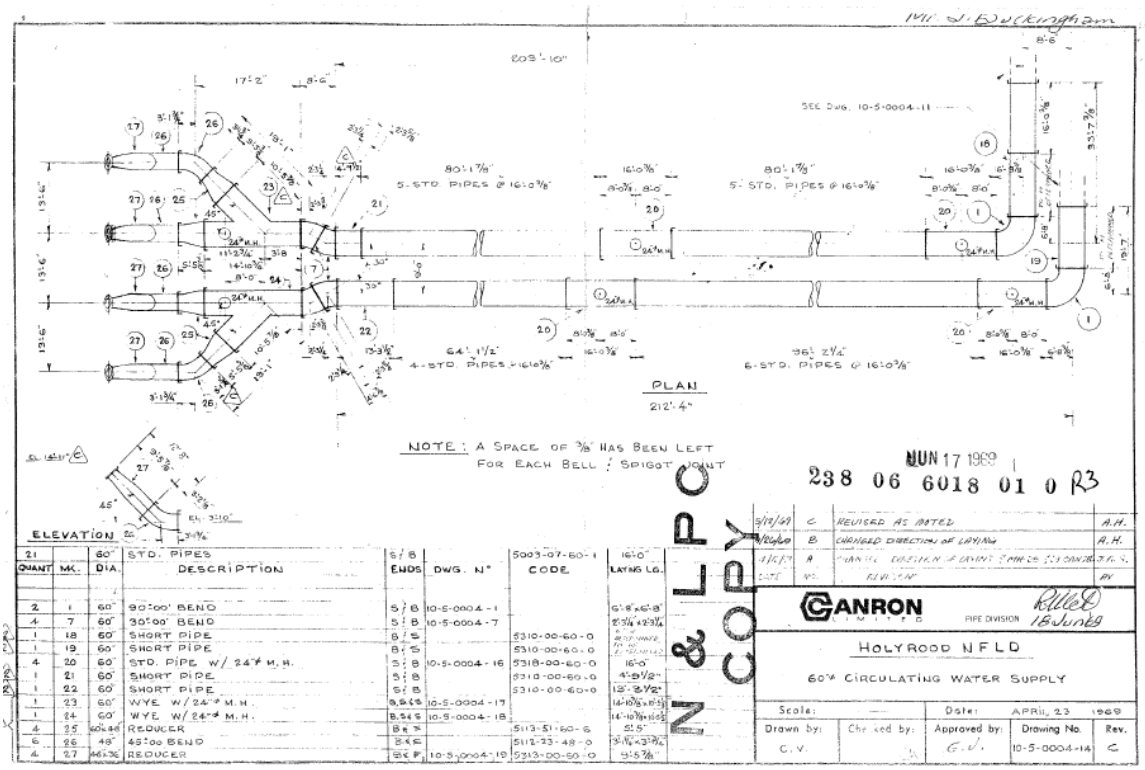



**FIGURE 9-23 STAGE 1 CIRCULATING WATER PIPING SCHEMATIC**



**FIGURE 9-24 UNIT 1 & 2 CIRCULATING WATER PUMPS**



FIGURE 9-25 UNIT 1 & 2 CIRCULATING WATER TRAVELLING SCREENS

### 9.2.10.2 History

| | |
|---|---|
| Manufactured/Delivered | 1970 |
| In-Service Date | Apr 1971 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2014 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 158 |
| Max Hours Generation Ops – to Dec 2015 | 188 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 212 |

### 9.2.10.3 Inspection and Repair History

**Cooling Water Pumps & Motors, Screens, and Piping Systems**

**CW Travelling Screens:** The travelling screen internals have been replaced on Unit 2 in the last 5 to 10 years. Interviews suggest that no recent issues have been experienced with these units. Visual examination confirmed that the Unit 2 screens generally appear to be in good condition.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

**CW Wash Water Pumps and Motors:** Externally, these are generally in a much corroded state, but were performing at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**CW Pumps:** CW pumps on all units are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been kept up and the units should be able to meet 2015 and 2020 timelines with satisfactory maintenance. Major pump overhauls are scheduled on a twelve year cycle.

**TABLE 9-72 MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

It is understood that a temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. The system has been designed to supply all three units if and when converted. In addition, there are interconnections between Units 1 to 3 CW systems to allow them to provide back-up for this purpose if necessary. The temporary pump set appears to be satisfactorily performing.

**CW Pump Motors:** Motors are electrically tested every year (following PM process).

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves and fittings from the pump to the inlet of the 162 cm (64 inch) concrete piping that goes underground to the unit condensers has generally experienced significant corrosion and some patching of the system has been done. It is in need of clean-up and testing for fitness of duty – a Level 2 inspection, or perhaps complete replacement.

**Cooling Water System Intake & Discharge:** The 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping that goes underground to the unit condensers has periodically been pumped out and walked down by station staff, although not in the last five years. There have been no obvious issues with the systems, although no detailed engineering evaluations and NDE work has been undertaken.

No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done.

Inspections are planned going forward on a three year cycle, per schedule below.

**TABLE 9-73 ANNUAL ASSET MAINTENANCE**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 9.2.10.4 Condition Assessment

The condition assessment of the Unit 2 cooling water system associated with steam systems is illustrated below in Table 9-74:

**TABLE 9-74 CONDITION ASSESSMENT – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 140 | 11 | Generally in good condition, however significant corrosion on major steel pipes, pumps and valves. | 4 | 200000 (30) | 10+ | 2041 | | | No | No | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Concrete pipe from Pumps to Condenser | 141 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe. | 4 | (60) | (20) | 2041 | | 2011 | Yes | Yes | 2000 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Concrete pipe from Condenser to outfall pit | 142 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize any internal mussel growth on the CW pipe. | 4 | (60) | (20) | 2041 | | 2011 | Yes | Yes | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 143 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | (10) | 2020 | 2012 | | Yes | No | 1971 |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 144 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | (10) | 2020 | 2012 | | Yes | No | 1971 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or not known by AMEC.

### 9.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 2 cooling water system associated with steam systems:

**TABLE 9-75 RECOMMENDED ACTIONS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 271486 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 194 | 11 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | N/A | 195 | 11 | Perform a detailed visible inspection, with some NDE spotchecks, within the next two to four years of the concrete intake and discharge pipes. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | N/A | 196 | 11 | Perform a detailed visible inspection with some NDE spotchecks of the concrete intake and discharge pipes. | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8106 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 197 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8107 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 198 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2012 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8106 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 199 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |
| 1296 | 7635 | 8093 | 271486 | 8107 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 200 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |

### 9.2.10.6 Risk Assessment

Table 9-76 below illustrates the risk assessment for the Unit 2 cooling water system associated with steam systems, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 9-76 RISK ASSESSMENT – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO-ECO RISK ASSESSMENT MODEL | | | SAFETY RISK ASSESSMENT MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | CW Concrete Pipe to Condenser | 171 | 11 | Concrete racking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | CW Pipe to Outfall Structure | 172 | 11 | Concrete racking. | (20) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | CW Pumps | 173 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | 4 kV Cooling Water Pump Motor | 174 | 25 | Electrical fault, mechanical fatigue, ops error. | (10) | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | CW Outlet Piping, Valves, Fittings | 175 | 11 | Corrosion - internal/external. | (10) | None | 3 | A | Low | 3 | A | Low | Major leak and repair/patch. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | CW Pumps | 176 | 11 | Corrosion - internal/external. | (10) | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | 4 kV Cooling Water Pump Motor | 177 | 25 | Electrical fault, mechanical fatigue, ops error. | (10) | None | 1 | B | Low | 1 | A | Low | Loss 60% of 1 unit generation. | Current inspection and maintain. |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | CW Outlet Piping, Valves, Fittings | 178 | 11 | Corrosion - internal/external. | (10) | None | 3 | A | Low | 3 | A | Low | Major leak and repair/patch. | Inspect and maintain. |

### 9.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 2 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 60 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

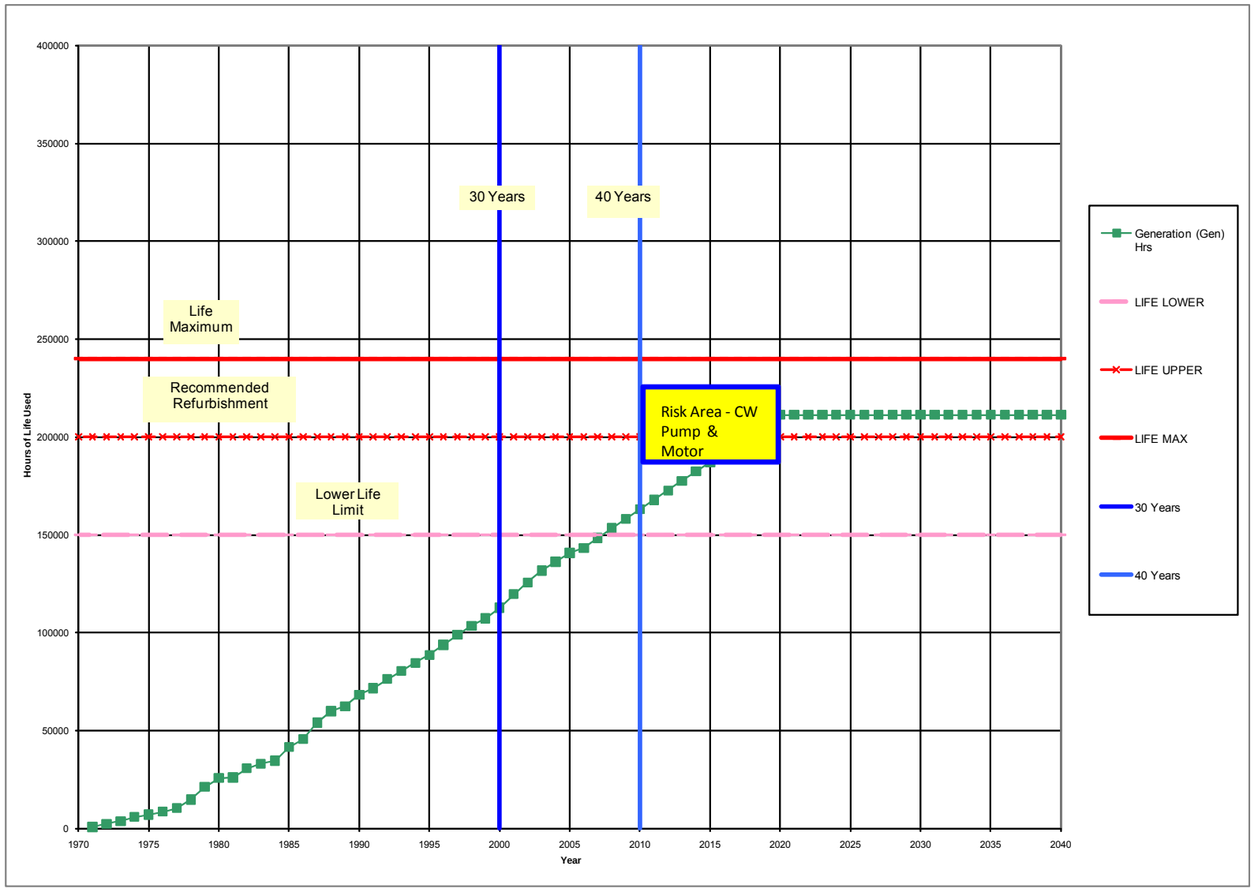



**FIGURE 9-26 LIFE CYCLE CURVE – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 2 cooling water system - associated with steam systems can likely reach the desired life (DL) end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motors. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

### 9.2.10.8 Level 2 Inspections – Unit 2 Cooling Water System - Associated with Steam Systems

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 9-77 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 9-77 LEVEL 2 INSPECTIONS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Concrete pipe to/from pump to condenser | 143 | 11 | Inspections - dry walk-down and NDE spotcheck. | 2011 | $6 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Steel pipe to/from condenser | 144 | 11 | Clean steel pipe and check thickness measurements. | 2011 | $6 |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | CW Pumps | 145 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). No Level 2 on 4 kV motor if current maintenance program continues. | 2011 | |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | CW Pumps | 146 | 11 | Perform planned inspections on one pump per unit in 2010 to 2012 (similar to Level 2). No Level 2 on 4 kV motor if current maintenance program continues. | 2011 | |

### 9.2.10.9 Capital Projects

The suggested typical capital enhancements for the system include:

**TABLE 9-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 2 COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 134 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Concrete pipe from pump to condenser | 135 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Concrete pipe from condenser to CW outfall pit | 136 | 11 | No capital investment required. | | |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | N/A | 137 | 25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | N/A | 138 | 25 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |

# 10 UNIT 3

## 10.1 Unit 3 - Key Systems

### 10.1.1 Asset 8298 – Unit 3 Generator

(Detailed Technical Assessment in Working Papers, Appendix 4)



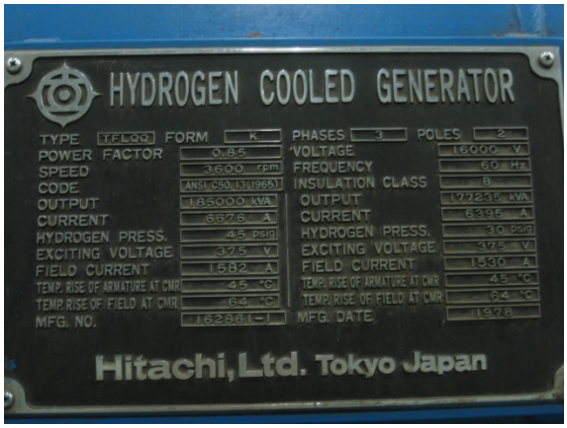



**FIGURE 10-1 UNIT 3 GENERATOR**

The equipment covered in this section includes:

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8194 #3 Turbine & Generator |
| Sub-Systems: | 8298 #3 Generator Assembly |
| Components: | 8299 #3 Generator Rotor |
| | 8304 #3 Generator Stator |
| | 8312 #3 Excitation System |
| | 8313 #3 Hydrogen System |
| | 8326 #3 Synchronous Condensing System |

#### 10.1.1.1 Description

The Unit 3 generator, supplied by Hitachi, Tokyo, is rated at 185 MVA, hydrogen cooled at 207 kPa (30 psi), 0.85 power factor. It has an overload rating of 185 MVA at 310 kPa (45 psi). It went into service in 1979. The last major inspection was by General Electric Canada in 2007.

The stator core and windings are flexibly-mounted in the stator frame, which contains four vertical hydrogen coolers. The stator windings operate at 16.0 KV and are indirectly cooled by hydrogen. The hydrogen is circulated throughout the generator in a closed system, at 310 kPa (45 psi) pressure, by an axial fan mounted on each end of the rotor. Isolated phase bus delivers the power from the generator to the unit transformer. It is generally similar to the stators of Units 1 and 2.

Although the Unit 3 generator was installed 10 years after the installation of Units 1 and 2, it uses an earlier rotor design, which incorporates several inherently weaker features. Unlike Units 1 and 2, this rotor is indirectly-cooled with hydrogen, and the retaining rings are shrunk onto the rotor shaft, and held in place with locking keys. The field windings are indirectly-cooled by hydrogen, axially fed through separate ventilation slots located between each winding slot. The hot rotor gas discharges radially from the central part of the rotor. The rotor shaft has a larger diameter and is longer than the rotor shafts servicing Units 1 and 2, but is less efficiently cooled. The rotor forging is believed to use an air-quenched forging that will have a higher fracture appearance transition temperature (FATT) and is more sensitive to brittle fracture in a cold environment. The retaining ring at the turbine end has an integral balance ring, while the retaining ring at the collector-end has a separate balance ring. Both retaining rings are held to the balance rings with shrink fits and locking keys.

The generator rotor is directly-coupled to the turbine, and is supported on bearings located in the end-shields of the stator frame. Hydrogen seals prevent the hydrogen from escaping around the rotating shaft. The seals are pressurized by oil and are located inboard of the bearings. Unlike Units 1 and 2, the field current is supplied to the field windings via four collector rings and sets of brush gear, outboard of the main bearing. There is an axial fan mounted on the end of the shaft, to cool the four collector rings, but it is believed there is no steady bearing to support the extra weight and shaft length.

In 1986, the generator was modified to operate as a synchronous condenser in order to provide voltage support to the Island Interconnected transmission system for electrical power that is transmitted over large distances. The synchronous condenser drive includes a Siemens 4 kV, 1500 HP induction drive motor (known as a pony motor), a Philadelphia Gear Starter Drive Gearpak (Model HL60/9HS), and a SSS Clutches Size 60T SSS Clutch and casing assembly, as well as associated auxiliaries (extension shaft, flexible coupling, hydraulic transmission). During this operating mode, the generator is de-coupled from the turbine and is accelerated up to synchronous speed using the pony motor drive and “disk-pack” clutch in the Philadelphia Gear Starter Drive Gearpak that is attached to the outer-end coupling of the generator rotor via the SSS clutch. As soon as the generator rotor reaches synchronous speed, the pony motor shuts down and is disengaged from the generator rotor via the SSS Clutch assembly. Unit 3 operates as a synchronous condenser for approximately seven months each year from May to November. The Unit 3 synchronous condenser is illustrated below in Figures 10-2 and 10-3.




FIGURE 10-2 SYNCHRONOUS CONDENSING UNIT



FIGURE 10-3 SYNCHRONOUS CONDENSING UNIT

The retrofit of the Unit 3 synchronous condensing capability required an extension of the turbine-generator support structure. One reliability issue is the lack of thrust and radial bearings on the stub shaft that connects the generator rotor to the SSS Clutch when the generator is de-coupled from the steam turbine for synchronous condenser operation. This allows the generator rotor to move axially and radially as operating conditions shift causing high vibration levels.

The excitation to the field is supplied by a Westinghouse static thyristor excitation system, with a fast-response automatic voltage regulator to control the generator voltage by adjusting the field current and MVAR output from the generator. The excitation has a high ceiling voltage capability in order to enable the generator to help the power system recover from faults and disturbances.

The auxiliary systems include:

- A static thyristor controlled excitation system fed from the generator terminals, with field flashing from a battery for initial energization, i.e. black start capability;
- A seal oil vacuum tank to remove the hydrogen that becomes entrained in the seal oil, (instead of the scavenging system used on units 1 and 2);
- A closed-loop distilled water cooling system and temperature controller to remove the heat from the generator, with a temperature controller to maintain constant cold hydrogen temperature;
- Potential transformers (PT's), located below the isolated phase bus, measure the generator voltage; Current transformers (CT's) mounted over the generator lead bushings measure the generator current. These devices provide signals to measure the generator output, and for the electro-mechanical protection relays;
- A vibration monitoring system that continuously monitors the vibration amplitudes at each turbine generator bearing in the control room, and alerts the operator to increasing vibration, especially during run-up, load changes and shut-down; and
- Generator protection that uses the original electro-mechanical relays. A digital multi-functional generator protection relay has been added, but at present it is primarily used for extra ground fault protection of the stator windings. It also provides supplementary alarms and sequence-of-events monitoring.

#### 10.1.1.2 History

The requirements for the generators on Unit 3 are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | 1988 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Inspection | 2007 |
| Next Major Overhaul/Inspection | 2016 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 126 | 35.1 |
| Hours - Ops to Gen End Date Dec 2015 | 170 | 44.0 |
| Hours - Ops to Gen End Date Dec 2020 | 179 | 67 |
| Hours – Ops to SC End Date Dec 2040 | 179 | 163 |
| Starts Actual - Ops to Dec 2009 | 328 | 46 |
| Starts - Ops to Gen End Date Dec 2015 | 400 | 58 |
| Starts - Ops to Gen End Date Dec 2020 | 460 | 83 |
| Starts – Ops to SC End Date Dec 2040 | 560 | 183 |

#### 10.1.1.3 Inspection and Repair History

**2007 Overhaul**

- Full stator re-wedge using similar wedges to those originally supplied by Hitachi (not top ripple springs);
- A damaged series connection and a damaged phase joint were repaired and cured;
- Stator frame was realigned with the new T-G shaft position;
- Turbine generator shaft was realigned to minimize the bending stress at the coupling;
- Some rotor slot end-wedges had migrated and were moved back into position and staked;
- Field winding measurements were taken but no repairs were necessary;
- Hydrogen seals were cleaned, segments lapped, and clearances were adjusted;
- Bearing journals were cleaned and strap lapped;
- Water-pressure test done on hydrogen coolers – OK; and
- New bearings and seals were installed in the seal oil vacuum pump.

**2001 Overhaul**

- New retaining rings were installed on the rotor and a broken packing block was replaced;
- The field windings were reported to be in good condition – no serious defects were found;
- Coupling bolt hole #11 was badly scored. It was honed smooth and an oversize bolt was installed;
- Hydrogen coolers were water-tested and found satisfactory. New gaskets were installed;
- CE seal upper and lower seal insulation frames were replaced;
- Hydrogen seals were cleaned, segments lapped, and clearances were adjusted; and
- Score marks were lapped out of the seal oil vacuum pump, and their seals were replaced.

Note: Oil was not reported to have leaked into the generator during the 2001 and the 2007 inspections, despite the larger hydrogen seal clearances on the Hitachi seals permitting a higher seal oil flow. It is concluded that the vacuum seal oil treatment unit is more effective than the GE detraining tank and scavenging system on Units 1 and 2.

### 10.1.1.4 Condition Assessment

The Unit 3 generator and its auxiliary systems are in reasonably good condition for their age.

- Stator Core: satisfactory, based on EI-cid test results;
- Stator Windings: satisfactory after 29 years, but the re-wedged bars are likely to loosen again;
- Rotor forging: Not known - no NDE checks have been done for 14 years or more. (concerns are based on design details);
- Field winding: satisfactory, per CGE report 2001, (there are some concerns, based on experience with similar Hitachi and GE generators in Canada); and

Details of the sub-systems are presented in Table 10-1 below and in more detail in Appendix 4.

**TABLE 10-1 CONDITION ASSESSMENT – UNIT 3 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | N/A | 10 | 4 | Stator: core - satisfactory; Windings: Satisfactory, wedges likely loose.<br>Rotor: Forging: Not known, likely satisfactory - no NDE for 14 years; Winding: Satisfactory, but concerns with similar units Overhaul required in 2016. | 4 | 200000 (30) | 10 | 2041 | 2016 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Core | 11 | 4 | Forging: Satisfactory to good condition in 2007. See windings. | 4 | 200000 (40) | 15 | 2041 | 2016 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Winding | 12 | 4 | Field Winding: Satisfactory, wedges likely loose. Generator has inherently weak design features incorporated (fretting of the locking keys, and of the top turns of copper at the ends of the rotor below the retaining ring leading to damaged top cap insulation and shorted field turns; risk of a broken top turn creating arc damage to the retaining ring; risk that fretting at the locking keys and shrink fit can lead to a fatigue crack developing in the rotor forging shaft, necessitating its replacement). Insulation found in satisfactory to good condition. | 4 | 200000 (30) | (6/15) | 2041 | 2016 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Core | 13 | 4 | Core - satisfactory to good. The stator core and frame are reported to be in good condition, with no looseness or fretting damage at the bore, or at the outside flexible mounting. GE reported show no significant core deterioration in 2003, and that the stator core is fit to be re-wound. | 4 | 200000 (40) | (10) | 2041 | 2016 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Winding | 14 | 4 | Windings: Satisfactory condition. Wedges likely loose, but good insulation condition in 2007. High winding temperatures due to low operating hydrogen pressure, 182 KPa versus rated value of 310 KPa. The stator core temperature is not monitored continuously, although this is desirable for synchronous condenser operation. | 4 | 200000 (30) | (10) | 2041 | 2016 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | | 15 | 4 | | 3a | 200000 (30) | 3 | 2041 | 2010 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8288 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | N/A | 16 | 4 | The hydrogen seal clearances are large on the air-side at 0.006 and 0.010 mil, where the differential pressure is 210 KPa: likely why considerable oil leakage out of the #6 bearing onto the IPB. The hydrogen-side clearances are more typical at 0.009 and 0.012 mils. In 2007, the hydrogen seal assemblies were dismantled, cleaned and lapped to obtain matching contact with the shaft. The seal oil vacuum pump was cleaned and inspected, and new bearings and seals were installed. | 4 | 200000 (30) | 10 | 2041 | 2010 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8318 | 3 | U3 GENERATOR | GENERATOR | GENERATOR CO2 GAS PURGE | N/A | 17 | 4 | No issues identified, aside from system capacity and supply limits. | 3a | 200000 (30) | (10) | 2041 | 2011 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8321 | 3 | U3 GENERATOR | GENERATOR | GENERATOR COMPRESSED AIR | N/A | 18 | 4 | No issues identified. | 4 | 200000 (30) | (10) | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 8322 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR HYDROGEN COOLING | N/A | 19 | 4 | In 2007, the hydrogen seal assemblies were dismantled, cleaned and lapped to obtain matching contact with the shaft. The seal oil vacuum pump was cleaned and inspected, and new bearings and seals were installed. The hydrogen cooler leak tested satisfactory. | 4 | 200000 (30) | 10 | 2041 | 2011 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8298 | 99039100 | 0 | 3 | U3 GENERATOR | GENERATOR | PARTIAL DISCHARGE ANALYSIS | N/A | 20 | 4 | Not functional. | 10 | 200000 (30) | 1 | 2041 | 2010 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8312 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 21 | 4,6 | See detail below | 10 | 200000 (30) | 3 | 2041 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8312 | 271679 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | N/A | 22 | 4,6 | System operates very well. Annual maintenance check in 2009. Modifications to the AVR in 2000. Supplier support and parts limited, but some parts available on site. | 10 | 200000 (30) | 3 | 2041 | 2009 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITATION TRANSFORMER | N/A | 23 | 4,6 | Original dry transformer equipment installed in 1979. Unit has a moderately high level of risk due to its age, although tests in 2007 identified satisfactory results. Replacement with exciter recommended. | 4 | 200000 (30) | 3 | 2041 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | RT3 RECTIFYING TRANSFORMER | N/A | 25 | 5,6 | Installed in 1979 as part of Unit 3 Exciter system, the unit has a moderately high level of risk due to its age. A dry transformer, tests in 2007 identified satisfactory results. | 4 | (45) | 15 | 2041 | 2013 | | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8312 | 271681 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | FIELD BREAKER | N/A | 26 | 4,6 | Installed in 1979 as part of Unit 3 Exciter system, breaker has a moderately high level of risk due to its age. No issues identified in 2007 test. | 4 | 200000 (30) | 3 | 2041 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8326 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR SYNCRONOUS COND | GENERATOR SYNCRONOUS COND | N/A | 27 | 4 | System has generally performed well, but causing higher than normal generator vibration readings, primarily as a result of a lack of a thrust bearing. Its condition appears mechanically quite good, but likely will require a major overhaul in 2016. | 4 | 150000 (30) | 10 | 2041 | | 2016 | Yes | No | 1986 |

Notes: 1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

#### 10.1.1.5 Actions

The following table highlights a number of the issues and defects associated with Unit 3 generator and the actions recommended to address them.

**TABLE 10-2 8304 #3 GENERATOR STATOR**

| Issues | Recommended Actions |
|---|---|
| 1. There is a risk of oil leaking into the stator, reducing the effectiveness of the winding support. (Oil and grease has been found on the end-windings during recent past inspections of Units 1 and 2.) | 1. Keep the differential seal oil/hydrogen differential pressure constant and between 27 – 40 kPa (4 and 6 psi).<br>2. Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator<br>3. Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness.<br>4. Check the hydrogen consumption and seal oil consumption for leakage.<br>5. Check the liquid leak detector for oil deposits. |
| 2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm that the condition of the core is sound, before ordering a replacement stator winding for installation in 2012, see next item). | 1. Plan for an El-cid test during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot.<br>2. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection.<br>3. If a stator rewind is planned, carry out a high flux test of the stator core. Take infra-red photos of the core and note the hot spots (areas greater than 3 °C above the surrounding areas). |
| 3. The 5 KV Megger readings are considerably lower than the GE units 1 and 2. It is believed this is due to high moisture present during the test, as the DC hipot test results were good (low and uniform leakage current in each phase). | 1. At the next major inspection, repeat the 10 KV Megger test, and the DC hipot test at 34 KV. (make sure the windings are clean and dry before doing the tests) |
| 4. The stator was fully re-wedged with flat wedges in 2007. This wedging system has been found to require frequent re-tightening during past inspections. Windings firmly in place and no loosening of the wedges/windings has occurred. | 1. Carry out a wedge tap survey, to check for loose wedges, and re-wedge any slots with more than 2 adjacent loose wedges or more than 4 loose in any slot.<br>2. Visually inspect the core teeth for signs of fretting dust or “grease”. |

| Issues | Recommended Actions |
|---|---|
| 5. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance. | 1. Take Doble test measurements at each major inspection, after the windings have been cleaned and tightened. |
| **A. Operation** | |
| 1. The stator winding and core RTD's do not read credible values. They are too low. | 1. Using the GE calibration from the last outage, monitor the most accurate RTD of each phase, and the hottest core RTD, on the DCS display. |
| 2. The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above) | 1. Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary. |
| 3. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results. | 1. When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress.<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line.<br>3. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry. |
| 4. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation. | 1. Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator. |

**TABLE 10-3 8299 #3 GENERATOR ROTOR**

| Issues | Recommended Actions |
|---|---|
| 1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 2001. (Defects have been found in other similar rotors after less than 30 years operation). | 1. Remove the retaining rings and the slot wedges.<br>2. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings. |
| 2. The condition of the end-windings is not known and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed. | 1. Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections. |
| 3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraded, overheated, or crushed by the retaining rings. | 1. Check the insulation blocks and re-place or re-tighten as necessary. (note the dust found probably contains asbestos). |
| 4. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to bearing wear, and it appears that the foundation is settling over time. | 1. Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well as the MW load.<br>2. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights.<br>3. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection. |
| 5. There is no record of the generator bearings being re-metalled but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor Babbitt bond, and electrical damage. The #5 bearing insulation was found defective. | 1. Re-furbish both generator bearings.<br>2. NDE the bearing Babbitt for good bond with the shell.<br>3. Check the surface for even wear<br>4. Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually.<br>5. Replace if defective. Replace oil deflectors. |

| Issues | Recommended Actions |
|---|---|
| **A. Operation** | |
| 1. The field current is not credible, it is much too low. | 1. Check the source and calibrate the DCCT, or use the field current value shown on the exciter. |
| 2. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the field winding insulation). | 1. Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or<br>2. Obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display. |
| 3. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound). | 1. Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core. |
| 4. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation). | 1. Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft.<br>2. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or<br>3. Install a Sohre grounding brush and shaft current and voltage monitoring system. |
| 5. During the major inspection outages, and the switchover to synchronous condenser operation, moisture collects on the stator and rotor windings. (Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage). The moisture greatly affects the Megger and DC hipot test results, and leads to pessimistic assessment of aging and reduced remaining life of the windings.. | 1. - When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress<br>2. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line.<br>3. The rotor should be kept in a clean conditions “tent” and air heaters installed to keep the windings warm and dry. |

**TABLE 10-4 8313 #3 HYDROGEN SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. The seal oil vacuum pump is a high maintenance item. The level control and the vacuum pump require preventive maintenance at every major inspection, to prevent foaming, and remove moisture effectively, and minimize the risk of oil entering the generator. | 1. Replace the seals, and gaskets, and check the operating level in the tank, at both 207 and 310 kPa (30 and 45 psi) hydrogen pressures.<br>2. Hitachi recommends the seal oil system be flushed regularly, to prevent contamination of the controls. Carry out preventive maintenance on the vacuum pump |
| 2. The hydrogen coolers were leak tested and found satisfactory but GE recommended the gaskets be replaced at each major inspection. | 1. Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!) |
| 3. The liquid leak detector valve is prone to failure (it had incorrect flanges and gaskets on units 1 and 2 | 1. Check the operation of the liquid leak detector relay, and service the parts. ).(Frequent operation wastes hydrogen). |
| 4. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater. | 1. Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, check for hydrogen leaks, especially at the purity meter and sampling valves. |
| 5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve.<br>2. Locate and repair hydrogen leaks ASAP. |
| **A. Operation** | |
| 1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings. | 1. Locate and repair the hydrogen leaks.<br>2. Increase the hydrogen pressure to 207 kPa (30 psi). |
| 2. The hydrogen consumption of each generator is not recorded. | 1. Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded. |
| 3. The cold gas temperature is low at 30 C, GE usually recommend a minimum of 35 °C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging. | 1. Ask GE to confirm the rotor forging is water-quenched, not air-quenched.<br>2. Increase the cold gas temperature setting to 35 °C, especially if the forging is air-quenched. |

| Issues | Recommended Actions |
|---|---|
| 4. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected. | 1. Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating. |
| 5. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator. | 1. Service the hydrogen pressure control valve.<br>2. Locate and repair hydrogen leaks ASAP. |

**TABLE 10-5 8312 #3 EXCITATION SYSTEM**

| Issues | Recommended Actions |
|---|---|
| 1. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing, - the risk of generator damage is highest during initial energization on AVR control. | 1. Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs. |

### 10.1.1.6 Actions - Unit 3 Generator

The following table highlights a number of the basic issues/defects found and the actions recommended to address them.

**TABLE 10-6 RECOMMENDED ACTIONS – UNIT 3 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | General | 12 | 4 | Reduce operating intervals between major outages to 6 years: poor condition of the stator windings, loosening of the end-winding supports (per 2005), extra fretting and insulation deterioration of the stator end-windings expected at the next major outage in 2016, continued oil leakage into the windings, current lack of stiffness of end-winding supports. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | General | 13 | 4 | Review generator drawings, contract information, and operating manual to clarify design details. | 2010 | 2 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 14 | 4 | Verify whether the rotor is an air-quenched forging, which is sensitive to brittle fracture, or is a water-quenched forging that is not sensitive to brittle fracture. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 15 | 4 | Confirm whether the rotor has 4 collector rings at the outer end of the rotor shaft (two per pole) instead of the 2 collector rings (one per pole), used on other generators of this rating, e.g. units 1 and 2. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 16 | 4 | Carry out electrical and mechanical inspection of the rotor in 2016. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 17 | 4 | Remove the retaining rings and perform a detailed NDE inspection. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 18 | 4 | Provide more details in next inspection of parts inspected, deterioration observed and severity or action needed. It should include photos, description of fretting dust, grease, sparking, accumulated dust and debris, as well as details of repair work done, e.g. cleaning out dust, re-fitting packing blocks, realigning turns in coils, turn insulation damage found and repairs made. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 19 | 4 | Make a visual check of the extent of restrictions of the radial gas cooling passages, and of any displaced turn insulation. Any accumulated debris in the radial ventilation ducts, the sub-slots, and in the end-windings should be blown or vacuumed out. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Field Winding | 20 | 4 | Perform annual 500 volt megger checks on the rotor, to confirm that there is no major deterioration of the ground insulation (below 3 Gig-ohms). | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Field Winding | 21 | 4 | Install a field winding temperature indicator in control room. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Field Winding | 22 | 4 | Use the volts/hertz element of the new multi-functional relay to ensure this condition is recognized and tripped promptly, as a back-up to the normal excitation/AVR limiters. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 23 | 4 | Check slots 57 and 59 at the CE, slots 8 and 10 at the centre of the core, but particularly slot 18, at the centre of the core, at the next inspection by el-cid test and with a boroscope. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 24 | 4 | Take and record the peak El-cid readings in each slot and check manually and record the stepped end–packets of plate. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 25 | 4 | Visually check with the hydrogen coolers removed the back of the core for fretting at the core bar supports, and for signs of overheating at the surface of the iron and restriction of the ventilation ducts. Take photos of main findings for future reference. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 26 | 4 | Carry out (if a complete rewind of the stator is contemplated in 2016) an El-cid test and a core high flux (loop) test, with thermovision camera check for hot spots, and temporary flux coils around the end-packets of iron - to ensure the core is in good enough condition to warrant the expenditure of a rewind. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 27 | 4 | Maintain a careful record should be kept of all stator core deterioration found, especially if it is not repaired. Manufacturers' records are generally too brief and inadequate; the inspection summaries outlined in the IEEE press book "Inspection of Synchronous Machines" by I. Kerszenbaum and G. Klempner provide a more detailed record, and have been endorsed by EPRI. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 28 | 4 | Take Doble reading before and after the windings have been maintained, Doble test readings for 2007, or for earlier inspections should be obtained and updated when the 2016 readings are available. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 29 | 4 | Take the partial discharge readings of the slot part and of the end-winding part every year, at full load. Have a set of data analyzed by IRIS a year before the 2016 outage, to help evaluate whether a stator rewind is necessary or desirable. | 2014 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 30 | 4 | Perform annual 5 KV megger readings - the simplest and most basic indication of the insulation condition, and is often done annually, or every two years. A reading below 4 Gig-ohms is considered unsatisfactory for this insulation system. | 2011 | 1 |

Table 10-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 31 | 4 | Perform Doble test in service. Care must be taken to compare only similar conditions, e.g. clean or dirty, and tests should be consistently in hydrogen (preferably not in air). Some users take Doble measurements every two years to obtain a better historical record, as an alternative to high voltage testing. The Doble test energizes all the coils in each phase up to rated phase voltage, and is considered a less harmful and less riskier test on old dirty or greasy insulation. It requires splitting the neutral connections more frequently, which increases the risk of a hot joint developing in these connections that can overheat and damage the bushings and the current transformers. It shows when accumulated dirt and grease from loose windings warrant bringing forward the next major inspection. An insulation power factor reading higher than 2.5 %, or a tip-up of more than 1%, after cleaning, would indicate the insulation is in very poor condition, and a rewind is required. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 32 | 4 | Measure the wedge tightness during the 2016 inspection, to see how much looseness has developed. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 33 | 4 | Carry out electrical tests on the windings in 2016, as in past years. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 34 | 4 | Plan for stator rewind in 2020. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Core | 36 | 4 | Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Field Winding | 37 | 4 | Stator Winding: Obtain Doble test data and on-line partial discharge measurements. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core | 38 | 4 | Rotor Forging: A full NDE inspection of the high-stress areas of the forging and attachments. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Winding | 39 | 4 | Field Winding: A detailed inspection of the field winding should be carried out, and a flux probe should be installed to check for shorted field turns. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | Hydrogen | 40 | 4 | Install a hydrogen consumption "totalizer" in each hydrogen supply line, for recording daily and checked for leaks. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | N/A | 41 | 4 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 2 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 3 | U3 GENERATOR | GENERATOR | GENERATOR CO2 GAS PURGE | N/A | 42 | 4 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 2 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 3 | U3 GENERATOR | GENERATOR | GENERATOR COMPRESSED AIR | N/A | 43 | 4 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 2 |
| 1296 | 8193 | 8194 | 8298 | 8322 | 3 | U3 GENERATOR | GENERATOR | GENERATOR HYDROGEN COOLING | | 44 | 4 | Maintain hydrogen pressure steady at the rated value of 310 KPag to simplify differential pressure controller operation and help to ensure a constant and appropriate oil flow through the hydrogen seals, reducing the risk of a seal oil spill into the generator. Also reduces the risk of the sealant at the stator end shields cracking and permitting a hydrogen leak. It will also avoid a change in the bearing height, and alignment of the rotor, which can increase the bearing vibration levels. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8298 | 99039100 | 3 | U3 GENERATOR | GENERATOR | PARTIAL DISCHARGE ANALYSIS | N/A | 45 | 4 | Repair and monitor results for generator condition analyses. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8312 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 46 | 4,6 | Replace Unit 3 static exciter. | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271679 | 3 | U3 GENERATOR | EXCITER | EXCITER | Static Exciter | 47 | 4,6 | Replace Unit 3 static exciter. | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 3 | U3 GENERATOR | EXCITATION TRANSFORMER | EXCITATION TRANSFORMER | N/A | 48 | 4,6 | Replace Unit 3 static exciter rectifying transformer. | 2012 | 1 |

### 10.1.1.7 Risk Assessment

The risk assessment associated with the Unit 3 generator, both from a technological perspective and a safety perspective, is illustrated below in Table 10-7.

**TABLE 10-7 RISK ASSESSMENT – UNIT 3 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | | 13 | | See detail below. | 10 | | | | | | | | | |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Forging and Field Windings | 14 | 4 | Electrical failure - EOL. | 15 | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016. |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | Rotor Forging and Field Windings | 15 | 4 | Mechanical failure retaining rings. | 15 | None | 2 | D | Medium | 2 | D | High | Loss of unit generator and SC capability. Potential life threatening. | Removal of the retaining rings and inspection in 2016. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core and Frame | 16 | 4 | Electrical - sustained over-fluxing off–line (e.g. if the PT has one phase open or a blown fuse). | 15 | None | 3 | C | Medium | 3 | C | High | Loss of unit generator and SC capability. Potential serious injury situation. | Extra V/f protection is desirable if the generator is energized on AVR control, as core damage occurs faster, because it goes to ceiling excitation (typically 160% rated flux). It should be noted that this V/f protection may not be applicable if the generator is energized on manual control. The standard protection against over-fluxing is the volts/hertz relay. It is recommended that the V/f element of the new generator multi-functional relay be set up to provide back-up protection, especially during off-line conditions. Initial energization is the time of highest risk. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core and Frame | 17 | 4 | Mechanical damage - Inspection related. | 15 | None | 2 | B | Low | 2 | B | Low | Damage is local. | Repair during outage. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core and Frame | 18 | 4 | Mechanical - loose plates vibrating in the magnetic field then break off and damage the stator winding, more prevalent at the core ends. | (6/15) | None | 3 | C | Medium | 3 | B | Medium | Loose plates break off and damage the stator winding. | Check for signs of red iron oxide dust in the stator bore are the standard sign of loose iron, and can be confirmed by pushing a paint scraper between the plates. Loose areas can usually be treated with penetrating epoxy and re-tightened by driving tapered wedges into the loose packets of iron. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core and Frame | 19 | 4 | Electrical - failures of the stator winding, and/or poor stator winding ground protection. | 15 | None | 3 | D | High | 3 | C | High | Damage to stator core. | 2016 Inspection and repairs/stator rewind. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Core and Frame | 20 | 4 | Electrical - insulation/winding failure - most likely to occur during serious system over-voltage transients, | (6/15) | None | 3 | D | High | 3 | C | High | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable. | Recommend rewinding the stator in 2020. Evaluate techno-economic risk of deferral at next overhaul in 2016 based on new data collected. The generator is currently relying upon the lightning and surge arrestors fitted at the generator terminals to attenuate the surges, or upon the statistical unlikelihood of the worst over-voltage |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Windings | 21 | 4 | Mechanical/electrical - can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, which have poor mechanical properties. | (6/15) | None | 3 | D | High | 3 | B | Medium | Stator winding failure - possible stator core effects. GE contention that the insulation is at high risk of failing and cannot be considered to be reliable. | Recommend rewinding the stator in 2020. Evaluate techno-economic risk of deferral at next overhaul in 2016 based on new data collected. Very important to control the mechanical stresses that can open up the glued layers of insulation and lead to mechanical breakdown of the mica flakes, especially if re-wedging required. |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Stator Windings | 22 | 4 | Mechanical/electrical - an increasing risk that the end-windings will loosen again after seven years of operation after 2003 rewedging. The line-end coils and phase leads are at most risk, of distortion, and could fail during a severe or a sustained system fault condition. | (6/15) | None | 2 | D | Medium | 2 | B | Low | The line-end coils and phase leads are at most risk of distortion and could fail during a severe or a sustained system fault condition. | Wedge tightening and/or re-wedging. Repair line-end coils and phase leads during overhaul. Stator rewind. |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen System Pressure Control | 23 | 4 | Mechanical/electrical/fire. | 3 | None | 3 | C | Medium | 3 | D | High | Seal leak, hydrogen fire/expl - oil leaks into the stator if the flow rate is too high, and overheating and failure of the hydrogen seals if the flow rate is too low. | New hydrogen seals and totalizer. |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | Auxiliaries - Hydrogen System - Purity meter and dryer | 24 | | Electrical/fire. | 3 | None | 1 | C | Low | 1 | D | High | Hydrogen fire/explosion. | Recent replacement - monitor condition and maintain. |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8288 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | N/A | 25 | | Mechanical - loss, spill - hydrogen leak. | 10 | None | 1 | C | Low | 2 | C | Medium | Hydrogen fire/explosion. | Inspect and test per current maintenance program. |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8318 | 3 | U3 GENERATOR | GENERATOR | GENERATOR CO2 GAS PURGE | N/A | 26 | | Mechanical failure. | 10 | None | 1 | C | Low | 2 | C | Medium | Hydrogen fire/explosion. | Inspect and rest per current maintenance program. |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8321 | 3 | U3 GENERATOR | GENERATOR | GENERATOR COMPRESSED AIR | N/A | 27 | | Not addressed. | 10 | None | | | | | | | | |

Table 10-7 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8194 | 8298 | 8322 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR HYDROGEN COOLING | Auxiliaries - Hydrogen Coolers | 28 | 4 | Electrical/fire. | 10 | None | 1 | C | Low | 1 | C | Medium | Hydrogen fire/explosion. | Monitor condition and maintain. |
| 1296 | 8193 | 8194 | 8298 | 99039100 | 0 | 3 | U3 GENERATOR | GENERATOR | PARTIAL DISCHARGE ANALYSIS | N/A | 29 | | Measurement error. | 0 | None | 4 | D | High | 4 | A | Low | Missed generator problem. | Refurbish. |
| 1296 | 8193 | 8194 | 8312 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 30 | | See detail below. | | None | | | | | | | | |
| 1296 | 8193 | 8194 | 8312 | 271679 | 0 | 3 | U3 GENERATOR | EXCITER | EXCITER | Static Exciter Controls | 31 | 6 | Electrical fault, mechanical fatigue, ctrls fault, ops error. | 3 | None | 2 | C | Medium | 2 | A | Low | Loss 1 unit generation. Damage to unit. | Replace in 2012. |
| 1296 | 8193 | 8194 | 8312 | 271679 | 0 | 3 | U3 GENERATOR | EXCITER | EXCITER | Static Exciter | 32 | 6 | Electrical fault, mechanical fatigue, ctrls fault, ops error. | 3 | None | 2 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Replace in 2012 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | EXCITATION TRANSFORMER | EXCITATION TRANSFORMER | N/A | 34 | | Electrical fault. | 3 | None | 2 | C | Medium | 2 | B | Low | Electrical fire, unit overspeed. | Replace in 2012 |
| 1296 | 8193 | 8194 | 8312 | 271681 | 0 | 3 | U3 GENERATOR | FIELD BREAKER | FIELD BREAKER | N/A | 36 | | Electrical fault. | 10 | None | 2 | C | Medium | 2 | B | Low | Electrical fire, unit overspeed. | Replace in 2012 with exciter |
| 1296 | 8193 | 8194 | 8326 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR SYNCRONOUS COND | GENERATOR SYNCRONOUS COND | N/A | 37 | | Electrical fault, mechanical failure/fatigue, ctrls fault, ops error. | 10 | None | 2 | C | Medium | 2 | C | Medium | Unit VARS loss, Generator overspeed. | Inspect and Test per current maintenance program |

### 10.1.1.8 Life Cycle Curve and Remaining Life

Figures10-4 and 10-5 below illustrates the life cycle curve for the Unit 3 generator. It is broken into two parts – the generator and the exciter. Differences in the scenarios identified in Section 6 do not materially affect the curve. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

The generator figure below shows the operating hours as an electricity generator, in synchronous condensing mode, as well as the sum of the two. Only one set of curves is required, given that the major elements of the generator (stator and rotor windings and core) and the hydrogen system are the same age. One vertical line illustrates the timing of the next generator overhaul in 2016. The lowest two horizontal lines represent the ranges of expected generator life (primarily the rotor winding) for Holyrood Unit 3 based on current and historical information and expert opinion. The “Early Rotor Rewind Unit 3 Recommended” line is based on an estimated minimum remaining reliable rotor winding life of seven years at current generation levels. The other two represent longer rotor winding lives that may be achievable with decreasing reliability and higher failure risk, as well as a maximum 20 years likely for the stator and rotor cores.

The “Rewind Unit 3 Recommended” line is based on the estimated remaining reliable rotor and stator winding life of five years at current generation levels. The other two represent longer lives that may be achievable with decreasing reliability and higher failure risk. The two upper lines also represent a longer assessment of the remaining life of the rotor winding and maximum 20 years likely for the stator and rotor cores. The same curves apply as no major changes in equipment have taken place to date.

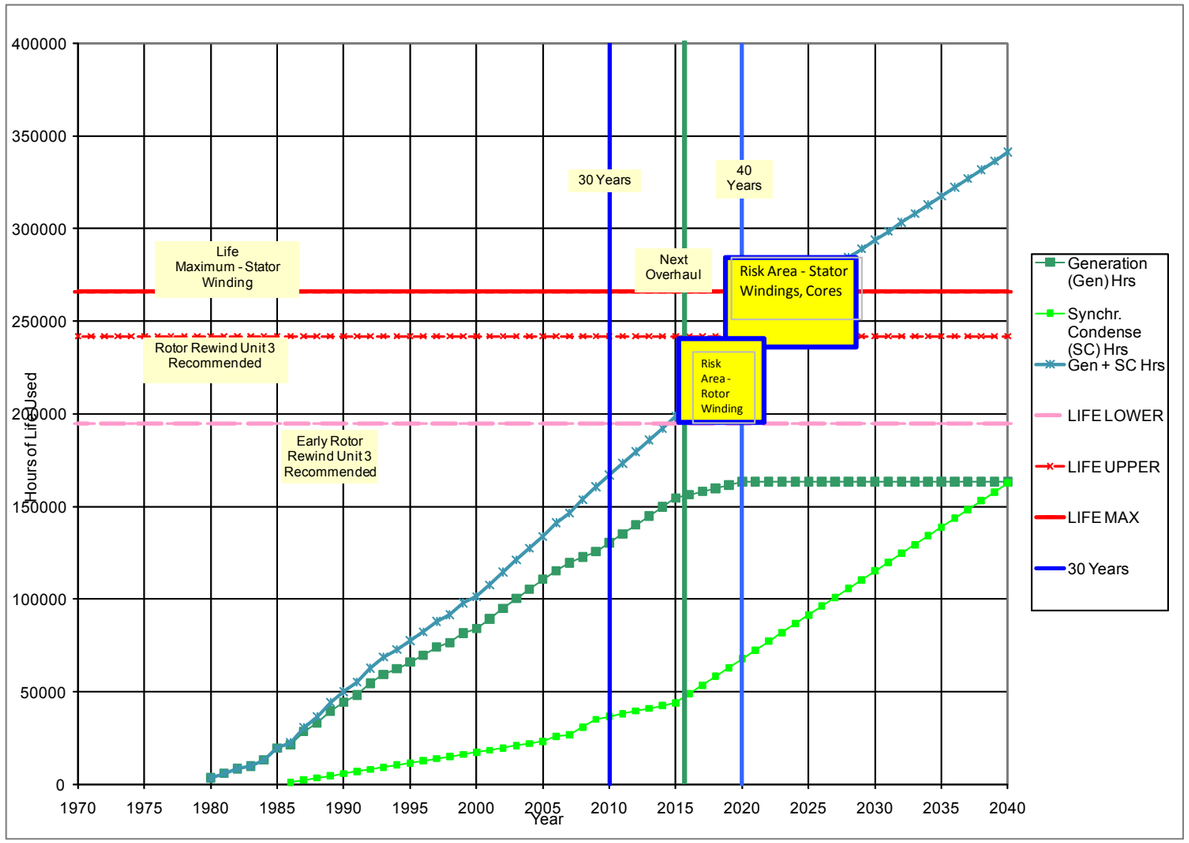



**FIGURE 10-4 LIFE CYCLE CURVE – UNIT 3 GENERATOR**

The exciter figure shows only the total operating hours as an electricity generator plus in synchronous condensing mode. It has one curve for the original equipment

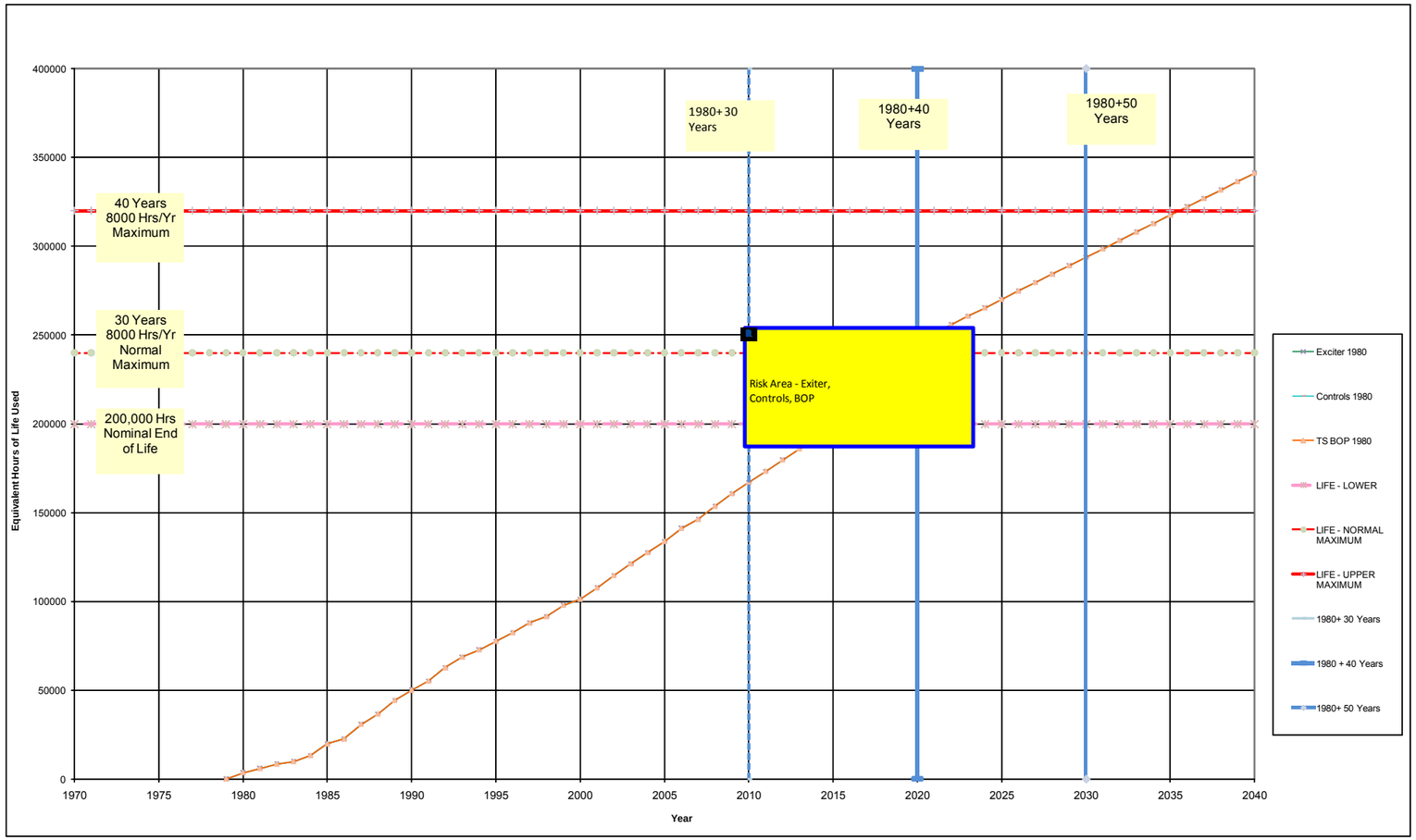



**FIGURE 10-5 LIFE CYCLE CURVE – UNIT 3 GENERATOR - EXCITER**

The curves indicate that the remaining life (RL) of the Unit 3 generator exceeds the desired life (DL) of 2016, which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2016 overhaul to assess key issues with the rotor windings, rotor core, and stator windings. The primary issue will be whether a rotor rewind is necessary in or about 2020. The remaining life (RL) of the Unit 3 generator exciter does not exceed the desired life (DL) and in fact has exceeded its normal expected life and should be replaced as soon as practical to meet the desired life of 2041.The highlighted near term risk areas include the rotor winding, exciter, the rectifying transformer, and BOP equipment. The curve also suggests that a nine year time between generator overhauls is impractical at this time in the generator's life and should be a six year cycle.

### 10.1.1.9 Level 2 Inspections – Unit 3 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make their next major outage/overhauls. This is provided that the plant maintains their current maintenance and inspection programs and addresses the issues identified in the Issues and Actions list. The current overhaul interval was increased from 6 years to 9 years based on a recent (2005) assessment by the Holyrood insurance supplier. This 9 year interval between majors is considered excessive, given the age and condition of the generators. A return to a six or seven year interval is considered necessary.

**TABLE 10-8 LEVEL 2 INSPECTIONS – UNIT 3 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | None | 9 | 4 | Level 2 allowance for 2011 Pre-Major Outage Inspection work. | 2011 | 1 | $100 |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | None | 10 | 4 | No Level 2 work required before the next inspection/overhaul. Work required to scope and be ready for the next planned inspection/overhaul includes:<br>- Review generator drawings, contract information, and operating manual to clarify design details. Check whether enough technical details exist to “reverse engineer” a specification for a replacement stator winding or a replacement field winding from Contractors other than Hitachi and GE<br>- Stator core: Core loop test and thermal image of core for hot spots, before the stator is re-wound.<br>- Stator Winding: Obtain Doble test data and on-line partial discharge measurements. | 2016 | 1 | $2,081 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | None | 11 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | None | 12 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | None | 13 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8288 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | None | 14 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8318 | 3 | U3 GENERATOR | GENERATOR | GENERATOR CO2 GAS PURGE | None | 15 | | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8321 | 3 | U3 GENERATOR | GENERATOR | GENERATOR COMPRESSED AIR | None | 16 | | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 8322 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR HYDROGEN COOLING | None | 17 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8298 | 99039100 | 0 | 3 | U3 GENERATOR | GENERATOR | PARTIAL DISCHARGE ANALYSIS | None | 18 | 4 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8312 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | None | 19 | 4,6 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8312 | 271679 | 0 | 3 | U3 GENERATOR | EXCITER | EXCITER | None | 20 | 4,6 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | EXCITATION TRANSFORMER | EXCITATION TRANSFORMER | None | 21 | 4,5 | No Level 2 required - include in generator overhaul. | 2016 | | $0 |
| 1296 | 8193 | 8194 | 8312 | 271681 | 0 | 3 | U3 GENERATOR | FIELD BREAKER | FIELD BREAKER | None | 23 | 4,6 | No Level 2 required - include in generator overhaul. | 2016 | | |
| 1296 | 8193 | 8194 | 8326 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR SYNCRONOUS COND | GENERATOR SYNCRONOUS COND | None | 24 | 4,6 | No Level 2 required - include in generator overhaul. | 2016 | | |

### 10.1.1.10 2011 Level 2 Inspection Requirements and Costs – Hydro Request

As part of the effort to optimize the requirements of the 2012, 2014, and 2016 Generator Outages, Hydro staff asked for an assessment of testing and inspections (Level 2) that could be performed in 2011 with the generator rotor in place. AMEC provided the following generic initial preliminary listing, with an allowance of $200,000 per unit. Given the major overhaul in 2016, AMEC recommends that those items that would assist in better preparing for the 2016 overhaul be undertaken and that an allowance of $100,000 per unit be set aside pending further detailed review.

The following are the tests that could be considered, with the scope adjusted as appropriate within the $100K/unit allowance suggested. It must be recognized that the list appears much more all-encompassing than it is. It is a generic checklist and will not and cannot address much of what needs to be addressed in the major outage in 2016 when the rotor is removed from the stator. There are several safety related issues that would have to be addressed when considering the scope.

**INSPECTIONS**

**Inspections – External Components:** The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage (likely not an issue – no vibration issue);
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling;
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected);
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free;
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking);
- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range); and
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check.

**Inspection – Stator Internal Components:** The following stator internal component items may be able to be inspected with the rotor in:

- Frame & support structure - compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers – likely very limited access; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing.
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind. and
- Winding TC's – inspect and check for function.

**Inspection – Stator Core:** The following stator core items could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Core back – partial through cooler openings;
- Core Compression plates – inspect at turbine end (difficult at generator end due to phase leads) for looseness and condition;

- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage; and
- Frame to Core Compression Bands – check through cooler openings. No stator casing underbelly inspection ports so unlikely to tighten if required – stator vibration does not appear to be an issue so likely unnecessary.

**Inspection – Stator Windings:** The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible. If the inner end shields can be moved out of way, up to about 50% of turbine end and 25% of the generator end (phase lead interference) can be checked.

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits;
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties;
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists);
- Tape separation/Girth cracking – inspect for near ends;
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation;
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks; and
- End Wedge Migration Out of Slot – inspection by eye or mirror (likely difficult to see (may not be applicable – locking mechanism).

**Inspection – Phase Bus Connectors and Terminals:** The following could be inspected with the Stator Core (Rotor In) to the Extent Possible. Access is very tight and may not be possible from a safety perspective. Lower part may be more accessible through bussing box.

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties;
- Phase Bus Phase Droppers: greasing, cracking insulation;
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable);
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues;
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition; and
- Generator Current Transformers (CT's): visual if in bushing box (IPB less accessible) - cracks, leaking resin, discolouration.

**Inspection - Hydrogen Coolers:** The hydrogen coolers could be inspected with the Rotor, assuming the coolers can be readily removed, in to the Extent Practical

- Tube clogging: visual inspection and descale;
- Tube leaks: hydrogen sensors, water inside casing, pressure test; and
- Tube thinning: eddy current tests.

**Inspection – Rotor:** The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning;
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate;
- Bearings & Journals: (if bearing dismantled) journals, Babbitt materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition (including tiny rounded electrical pits); bearing insulation and grounding brush integrity;
- End Wedges (using boroscope): discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring;
- C-Channel Subslot (if applicable): physical damage - boroscope examination through slot under retaining ring may be possible but very difficult;
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition;
- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?);
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical;
- Couplings and Coupling Bolts: chafing, fretting, thread condition;
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing – megger; and
- Hydrogen Seals: Requires hydrogen seals be dismantled. Seals: inspect Babbitt and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for Babbitt bonding to shell, Insulation resistance – megger seal insulation to ground.

**Inspection – Auxiliaries:** The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check;
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition;
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check; and
- Exciters: Electrical and Mechanical systems.

**TESTS**

**Test – Stator:** The tests to be further evaluated for the Stator with the rotor in could include:

- Stator Winding Electrical Tests – dry, phase isolation
    - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely;
    - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;

- A Doble test can be done to measure the insulation power factor and tip-up of the stator winding, with the rotor in place. (all the stator coils are raised in steps, up to rated phase voltage, during this test, and each phase is energized separately);
- DC Hi Pot: high voltage to winding (each phase separately or all) – done in hydrogen
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections;
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation;
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown; and
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges).

**Test – Rotor:** The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum.
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections;
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely;
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture;
  - Shorted turns Detection;
  - Off-Line Testing: winding impedance measurement during acceleration and deceleration for comparison with past tests (Low Voltage DC – Volt Drop Shorted Turn Test likely preferred otherwise);
  - Hydrogen Seals: NDE - Megger seal insulation;.
  - Bearings: Megger bearing insulation.

### 10.1.1.11 Capital Projects

The suggested typical capital enhancements for the Unit 3 generator include:

**TABLE 10-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 GENERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | N/A | 13 | 4 | 3 | Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2016. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8299 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR ROTOR | N/A | 14 | 4 | 3 | Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | N/A | 15 | 4 | 3 | Plan for stator rewinding in 2020, subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment in 2016 with input from operational testing from 2011 onward. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN.HYDROGEN GAS SYSTEM | N/A | 16 | 4 | 3 | Install a hydrogen consumption “totalizer” in each hydrogen supply line. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8288 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | N/A | 17 | 4 | 3 | Provide electrical control (both “On” and “Off”) for the AC and DC seal oil pumps in parallel with the local controls in the Control Room. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8318 | 3 | U3 GENERATOR | GENERATOR | GENERATOR CO2 GAS PURGE | N/A | 18 | | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8321 | 3 | U3 GENERATOR | GENERATOR | GENERATOR COMPRESSED AIR | N/A | 19 | | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8298 | 8322 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR HYDROGEN COOLING | N/A | 20 | 4 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8298 | 99039100 | 0 | 3 | U3 GENERATOR | GENERATOR | PARTIAL DISCHARGE ANALYSIS | N/A | 21 | 4 | 3 | Repair/refurbish. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8312 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | N/A | 22 | 4,6 | 3 | Replace Unit 3 static exciter (also impact the Unit 3 rectifying transformer). | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271679 | 0 | 3 | U3 GENERATOR | EXCITER | EXCITER | N/A | 23 | 4,6 | 3 | Replace Unit 3 static exciter (also impact the Unit 3 rectifying transformer). | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | EXCITATION TRANSFORMER | EXCITATION TRANSFORMER | N/A | 24 | 4,5 | 3 | Replace Unit 3 static exciter rectifying transformer. | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271681 | 0 | 3 | U3 GENERATOR | FIELD BREAKER | FIELD BREAKER | N/A | 26 | 4,6 | 3 | No capital, subject to assessment of techno-economic need to replace with exciter. | | |
| 1296 | 8193 | 8194 | 8326 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR SYNCRONOUS COND | GENERATOR SYNCRONOUS COND | N/A | 27 | 4 | 3 | Modify synchronous condenser - thrust bearing. | 2011 | 1 |

### 10.1.2 Asset 8270 – Unit 3 Generator Lube Oil System

(Detailed Technical Assessment in Working Papers, Appendix 9)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8194 #3 Turbine & Generator |
| Sub-Systems: | 8270 #3 Turbine Oil Systems<br>8275 #3 Turbine Lubricating Oil<br>8294 #3 Jacking Oil Systems |
| Components: | 8271 #3 Tank & Equip<br>8274 #3 Purification<br>8276 #3 Flushing Oil Pump<br>8277 #3 AC Pump South<br>8281 #3 DC Pump<br>8546 #3 Aux Oil pump<br>8285 #3 Jacking Oil pump |

#### 10.1.2.1 Description

The Unit 3 generator lube oil system consists of:

- One turbine lube oil tank with three oil pumps;
- Two 100% duty oil coolers;
- Two 100% duty oil filters;
- One jacking oil pump system located near the lube oil tank;
- One oil purifier; and
- One main oil turbine shaft driven pump located in the front standard of the steam turbine.

The lube oil tank has a capacity of 18000L (4754 US gallons) of lubricating oil.

Three pumps, two 100% duty lube oil coolers, associated oil piping and valves are located within the tank. The AC Motor driven “Aux Oil Pump” operates at a discharge pressure of 1210 kPa and supplies bearing oil and power oil (relay oil) to drive the Main Stop Valves, Control Valves, and Combined Reheat / Intercept valves along with other valves and components requiring high pressure oil when the unit is started up or shut down and the turbine speed is less than 3600 rpm. The AC “Flushing Oil Pump” is used when lubricating oil is needed and the unit is on turning gear, operating at 315kPa. The “DC Flushing Oil Pump" operates at a discharge pressure of 272 kPa and provides lubrication to the bearings as the backup to the AC Oil Pump and the AC Flushing Oil Pump if all AC power is lost to the unit.

The two 100% duty oil coolers supply 35-45$^{o}$C lubricating oil to the unit and have exposed cooling water heads that are isolatable and removable in order to clean the tubes as required.

Unit 3 has two 100% duty lube oil filters located on the ground floor elevation which are capable of handling the full lubricating oil flow. One oil purifier is separately connected to the lube oil tank through a piping arrangement that allows for the water that has accumulated due to steam leakage and condensation to be removed from the lubricating oil.

The jacking oil pumping system located next to turbine lube oil tank on the ground floor elevation uses a separate piping arrangement connected to the lube oil tank and operates at a discharge pressure of 15.5 MPa with a flow rate of 11 USGPM. Jacking oil is used prior to operating the turbine/generator on turning gear to lift the turbine/generator rotors off the bearing babbitt surfaces and before engaging the turbine/ generator turning gear. The jacking system oil remains in service until the turbine reaches 2000 rpm on start up and restarts on shutdown at approx 2200 rpm.

Unit 3 steam turbine generator, unlike Units 1 & 2, has an internal shaft driven oil pump in the front standard, which at 3600 rpm supplies lubricating oil to the bearings and power oil (relay oil) to drive the east and west main steam stop valves, the control valves and the east and west combined reheat intercept stop valves along with various other valves and components associated with the unit.

#### 10.1.2.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | 1988 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2016 |

The thousands of hours associated with the analyses, and the number of starts per year are:

| | Generation (Gen) | Synchronous Condensing (SC) |
|---|---|---|
| Hours Actual - Ops to Dec 2009 | 126 | 0 |
| Hours - Ops to Gen End Date Dec 2015 | 170 | 1.5 |
| Hours - Ops to Gen End Date Dec 2020 | 179 | 25 |
| Hours – Ops to SC End Date Dec 2040 | 219 | 120 |
| Starts Actual - Ops to Dec 2009 | 482 | 0 |
| Starts - Ops to Gen End Date Dec 2015 | 554 | 5 |
| Starts - Ops to Gen End Date Dec 2020 | 614 | 30 |
| Starts – Ops to SC End Date Dec 2040 | 714 | 130 |

#### 10.1.2.3 Inspection and Repair History

The system was examined extensively as part of a plant fire protection system evaluation. It is in good condition and, with regular maintenance and inspection during major generator inspections, is capable of meeting the requirements for the generator up to 2041.

### 10.1.2.4 Condition Assessment

The system has been in service since Unit 3 was placed in service in 1980. Although this system is critical to the operation of the steam turbine/generator and may cause the unit to be shut down for short periods, the only likely major issue creating a longer shutdown would be the major failure of the lubricating oil piping system which cannot be easily inspected because the supply piping resides inside of the oil return piping back to the oil tank. Externally, the tank appears to be in good condition. Internal inspection reports were not available. Any failures of the oil pumps or the oil purifier are easily repaired. This system should continue to operate reliably for the time frames required. If this unit is required to support synchronous condenser operation after the generation mode is discontinued, it will be required to be in operation continuously and should not present any major issue.

All components of the generator lube oil system are expected to be able to make their next inspection date. All are expected to require more rigorous evaluation at that time. Most will be able with maintenance and replacement to meet the generation end dates. None are expected to be able to make their 2041 synchronous condensing end date without a major refurbishment and replacement program.

**TABLE 10-10 CONDITION ASSESSMENT – UNIT 3 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 8270 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 43 | 18 | See details below. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 44 | 18 | Lube oil system is in good condition. No NDE of piping was obtained and reviewed, but interviews indicated no issues. Failures of any of the oil pumps or the oil purifier are easily repaired. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | N/A | 45 | 18 | Lube oil tank appears to be in good condition. Internal inspection reports were not available. | 4 | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL PURIFICATION | N/A | 46 | 18 | Lube oil purification system is relatively new and in good condition. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB AC FLUSHING OIL PUMP | N/A | 47 | 18 | Original equipment. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE A.C OIL P/P SOUTH | N/A | 48 | 18 | Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 49 | 18 | Lube oil pumps in good condition based on interviews. Failures readily dealt with through backups and replacements as required. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AUXILIARY OIL PUMP | N/A | 50 | 18 | Original equipment. No issues identified with system. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL SYSTEM | N/A | 51 | 18 | Original equipment. No issues identified with system. | 3a | (30) | 10 | 2041 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL PUMP | N/A | 52 | 18 | Original equipment. No issues identified with system. | 3a | (30) | 10 | 2041 | 2013 | 2013 | No | No | 1980 |

Notes: 1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.1.2.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 lube oil system.

**10-11 RECOMMENDED ACTIONS – UNIT 3 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 76 | 18 | See details below. Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 77 | 18 | Flush lube oil, seal oil and seal oil bypass lines prior to the seasonal restart of the unit every year. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIP | N/A | 78 | 9 | Perform Level 2 inspections on oil storage tanks and internals. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL PURIFICATION | N/A | 79 | 9 | No recommended action. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE AC FLUSHING OIL PUMP | N/A | 80 | 9 | Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE A.C OIL P/P SOUTH | N/A | 81 | 9 | No recommended action. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 82 | 9 | No recommended action. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE AUXILIARY OIL PUMP | N/A | 83 | 9 | No recommended action. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL SYSTEM | N/A | 84 | 9 | No recommended action. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL PUMP | N/A | 85 | 9 | No recommended action. | | |

### 10.1.2.6 Risk Assessment

The risk assessment associated with the Unit 3 generator lube oil system, both from a technological perspective and a safety perspective, is illustrated below in Table 10-12.

**TABLE 10-12 RISK ASSESSMENT – UNIT 3 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | | 55 | | See detail below. | 10 | None | | | | | | | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | | 56 | | See detail below. | 10 | None | | | | | | | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIPMENT | Lube Oil Tanks | 57 | 9 | Corrosion, erosion. | 10 | None | 1 | A | Low | 1 | A | Low | Oil leak – containment overflow. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIPMENT | Lube Oil Pumps & Motors | 58 | 9 | Mechanical and/or electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIPMENT | Lube Oil Coolers | 59 | 9 | Mechanical failure/leaks. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Maintain and inspect full-flow filter and by-pass to reduce the risk of bearing damage. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIPMENT | Lube Oil Filters | 60 | 9 | Bearing failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL PURIFICATION | Lube Oil Filters | 61 | 9 | Mechanical and/or pluggage failure. | 10 | None | 1 | A | Low | 1 | A | Low | Water & particulate contamination. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AC FLUSHING OIL PUMP | N/A | 62 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE A.C OIL P/P SOUTH | N/A | 63 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 64 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AUXILIARY OIL PUMP | N/A | 65 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL SYSTEM | N/A | 66 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL PUMP | N/A | 67 | 9 | Mechanical electrical failure. | 10 | None | 1 | A | Low | 1 | A | Low | Unit shutdown – multiple systems. | Inspect and maintain. |

Notes: 1. The risk assessment for the lube oil pumps is based on the lube oil pump controls being added to the control room as per the recommendations of the 2009 Emergency Shutdown Procedure study.

### 10.1.2.7 Life Cycle Curve and Remaining Life

Figure 10-6 below illustrates the life cycle curve for the Unit 3 generator lube oil system. One curve is required, given that the major elements of the lube oil system are approximately the same age. There is insufficient information to develop specific accurate curves for the storage tank. Further detailed examination during the 2016 turbine overhaul should provide the basis going forward. The life curve is a plot of current and projected operating hours (generation plus synchronous condensing mode0 on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life (typically 200,000 operating hours, thirty years and 200,000 to 240,000 operating hours, and forty years, and 280,000 to 320,000 operating hours). Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

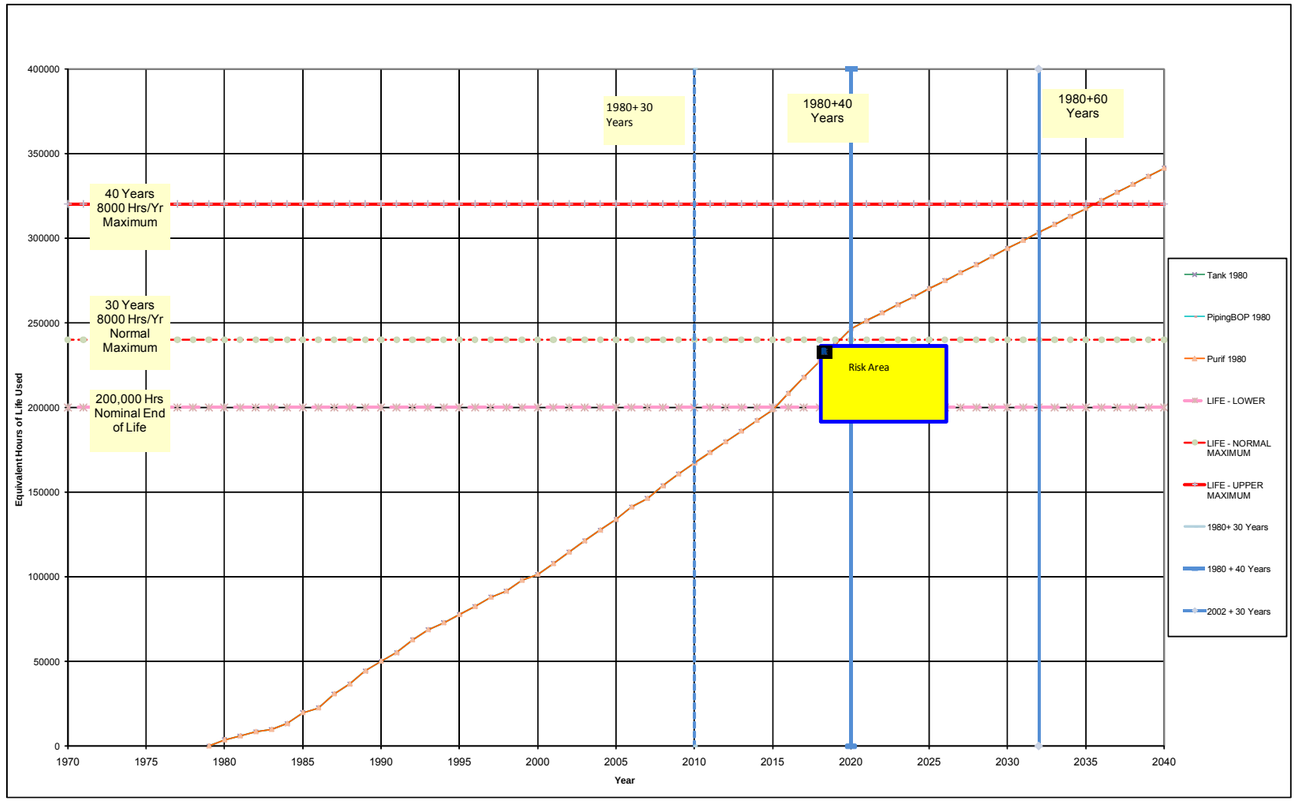



**FIGURE 10-6 LIFE CYCLE CURVE – UNIT 3 GENERATOR LUBE OIL SYSTEM**

The curves indicate that the remaining life (RL) of the Unit 3 generator lube oil system exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2041. Thus no specific dedicated Level 2 is required of the system as a whole, but sufficient inspection and testing will be required in 2013 steam turbine valve overhaul or the 2016 steam turbine generator overhaul to demonstrate the ability to meet the EOL date. The exception is the storage tank for which information was considered inadequate to form a firm conclusion and level 2 testing is recommended in 2011. The figure's highlighted risk areas is primarily operating hours driven and likely to shift further out in time after the 2016 turbine generator overhaul. The 2013 steam turbine valve overhaul and the 2016 overhaul/inspection are fundamental elements in changing the current assessment.

### 10.1.2.8 Level 2 Inspections – Unit 3 Generator Lube Oil System

Given the condition historical data reviewed, a Level 2 analysis of the lube oil storage tank is recommended. No other Level 2 analyses is required, provided the current inspection and maintenance program for the system is maintained and a more detailed inspection is performed at the turbine overhaul.

**TABLE 10-13 LEVEL 2 INSPECTIONS – UNIT 3 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 8270 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | None | 42 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | None | 43 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | None | 44 | 9 | No Level 2 required - include in steam turbine overhaul. | 2011 | 2 | $6 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL PURIFICATION | None | 45 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB AC FLUSHING OIL PUMP | None | 46 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE A.C OIL P/P SOUTH | None | 47 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE D.C. PUMP | None | 48 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AUXILIARY OIL PUMP | None | 49 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL SYSTEM | None | 50 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL PUMP | None | 51 | 9 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |

### 10.1.2.9 Capital Projects

The suggested typical capital enhancements include:

**TABLE 10-14 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 GENERATOR LUBE OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 8270 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | N/A | 44 | 9 | 3 | Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation. | 2012 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL SYSTEM | N/A | 45 | 9 | 3 | Replace turbine lube oil conditioners. | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL TANK & EQUIP | N/A | 46 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE OIL PURIFICATION | N/A | 47 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AC FLUSHING OIL PUMP | N/A | 48 | 9 | 3 | Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE A.C OIL P/P SOUTH | N/A | 49 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE LUBE D.C. PUMP | N/A | 50 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURBINE AUXILIARY OIL PUMP | N/A | 51 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL SYSTEM | N/A | 52 | 9 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8294 | 3 | U3 GENERATOR | TURBINE | TURBINE JACKING OIL PUMP | N/A | 53 | 9 | 3 | No capital required. | | |

### 10.1.3 Asset 8712 – Unit 3 Electrical and Control System Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendix 6)

The requirements for the Electrical and Control Systems associated with the Unit 3 generator are as follows:

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 8317 #3 Electrical Systems & Control |
| Sub-Systems: | 8317 #3 Electrical Systems & Control |
| Components: | 8698 #3 Relay Room Protection & Control<br>8704 #3 Main Controls<br>8713 #3 Generator Bus-duct and Connections<br>8750 #3 Battery Chargers<br>8751 #3 UPS3 Inverter<br>8757 #3 UPS4 Inverter<br>8763 #3 Battery Banks<br>271766 #3 Switchgear 4160V/600V.<br>271767 #3 Turbine Supervisory System<br>301711 #3 DCS<br>271769 #3 Static Exciter<br>**COMMON SYSTEMS**<br>271764 Common, Control Cables<br>271765 Common, Control Cables<br>309896 Common 600V Metric Plugs |

#### 10.1.3.1 Description

**Asset 8698, Unit 3 Relay Room Protection and Control**

**Generator G3 Transformer T3, ST3/ST4 and Auxiliaries P & C:** Manufactured by Canadian General Electric, and installed in 1979.

**Generator G3 and Transformer T3 Protection Panels:** These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications.

**Unit Transformer T3 and Unit #3 Protection Panel:** This panel utilizes GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications.

**Unit 3 Metering Panel:** This panel contains G3, T3 UST3 MWH meters and stator ground fault protection that was added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

**Transformer ST3/ST4 Protection Panel:** This panel utilizes GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation, and indications.

**Two Blank Panels:** One panel shows L47-1 Combiflex control relays.

The rear of the panels shows the original ASEA Combiflex relays and Agastat timers.

**Asset 8704 Unit 3 Main Controls**

The original Unit 3 main controls were console mounted and utilized, typically GE SBM type switches, incandescent indications, analog instruments and Panalarm annunciation. Modifications were made to adapt the generator, turbine and boiler controls to the Distributed Control System (DCS) and to replace some of the original controls, indications and annunciation.

G1, MW, Amps, MVAR's, kV, Field Volts, Speed Load Position, Load Limit position and Balance, are shown on the original analog instruments above the console, and are also indicated on the screens via the DCS.

Unit 3 valve and motor controls repeat relaying and transducers are situated in ASEA cabinets behind the control room. The system includes ASEA Combiflex relays and bases. The ASEA cabinets are in a hazardous state, with cabling so congested that it renders the doors in the vertical sections of the cabinet unable to be closed. Should connections or conductors require moving or tracing, catastrophic results may occur taking Unit 3 out of service for an indeterminate period of time.

**Asset 8713 Unit 3 Generator Bus-duct and Connections**

The generator bus-duct is a 3 phase isolated phase bus complete with PT's and a neutral cubicle manufactured by Westinghouse and installed in 1979.

**Asset 8750 Unit 3 Battery Chargers**

Unit 3, 129VDC Battery Charger 1, manufactured by CTS Canada, was installed in 1978. Charger 1 is a type 6732B 1978, 600V input, 129VDC system, with a 125A maximum rated charger output.

Unit 3, 258VDC Battery Charger 2, manufactured by CIGENTEC, Inc., was installed in 2001. Charger 2 is a type C3-250-250PMF3BHRGCU0DS2X6, 600V input, 258VDC system, with a 250A maximum rated charger output.

Other Information:

Unit 3, 258VDC distribution panel was manufactured by Westinghouse and installed in 1979 complete with breakers, typically FPE type GADC.

**Asset 8751 Unit 3 UPS3 Inverter**

The Inverter is a 9315 Series, and was manufactured by Eaton Powerware and installed in 2001. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries). 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS3 Inverter, via Distribution Splitter are as follows:

- Unit 3 UPS Panel No.3 in Unit 3 exciter room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit; and
- Unit 3 WDPF Panel, DP-3 relay room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit.

**Asset 8757 Unit 3 UPS4 Inverter**

The Inverter is a 9315 Series, and was manufactured by Eaton Powerware and installed in 2001. Battery manufactured by C&D Technologies, Inc. (UPS Dynasty batteries), 600V input (transformer 600V:480V into Inverter), 120/208V output, 30kVA rated power, 93Ah @ 20 hour rate to 1.75V per cell @ 77 °F (25 °C).

Other Information: 120/208V, 3 phase Distribution Panel-boards fed from UPS4 inverter, via Distribution Splitter are as follows:

- Unit 3 UPS Panel No.4 in Unit 3 exciter room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit; and
- Unit 3 WDPF Panel, DP-4 relay room, fed via 125A fused disconnect, Cutler-hammer, Type PL1, 3 phase, 4W, 225A, 42 circuit.

**Asset 8763 Unit 3 Battery Banks**

Unit 3 129VDC Battery Bank was manufactured by C&D Technologies, Inc. and installed in 1996. Battery Bank is a Model KCR-11 and is Flooded, Lead-calcium.

Unit 3 258VDC Battery Bank was manufactured by C&D Technologies, Inc. and installed in 1996. Battery Bank is a Model KCR-11 and is Flooded, Lead-calcium.

**Asset 271766 Unit 3 Switchgear, 4160V/600V**

Unit Board UB3 and Station Board SB34, (4160V) were manufactured by FPE and installed in 1980.

The 4160V switchgear, utilizes original draw-out ITE type 5HK power breakers. Protection, synch, and control relays are original CGE electro-mechanical. All feeders have Schweitzer.

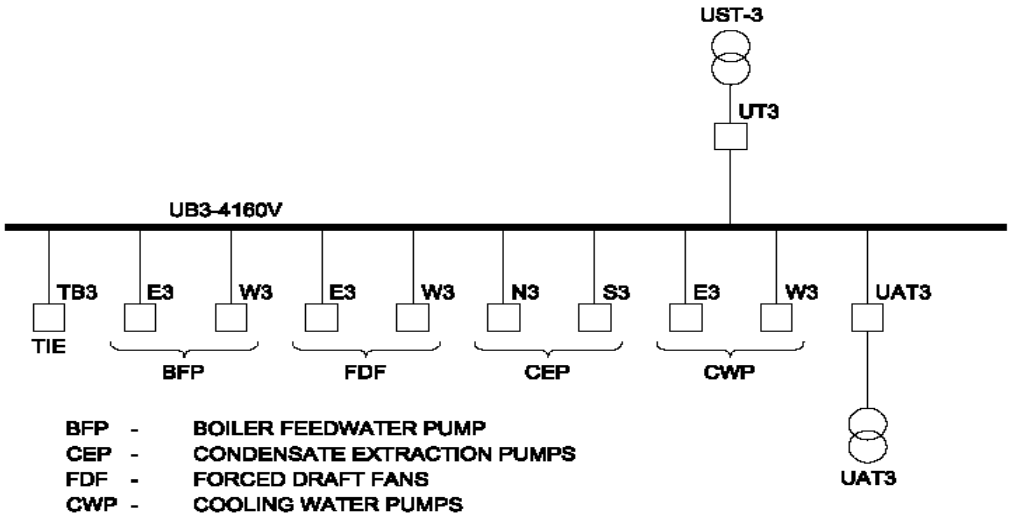



FIGURE 10-7 UB3 SWITCHGEAR

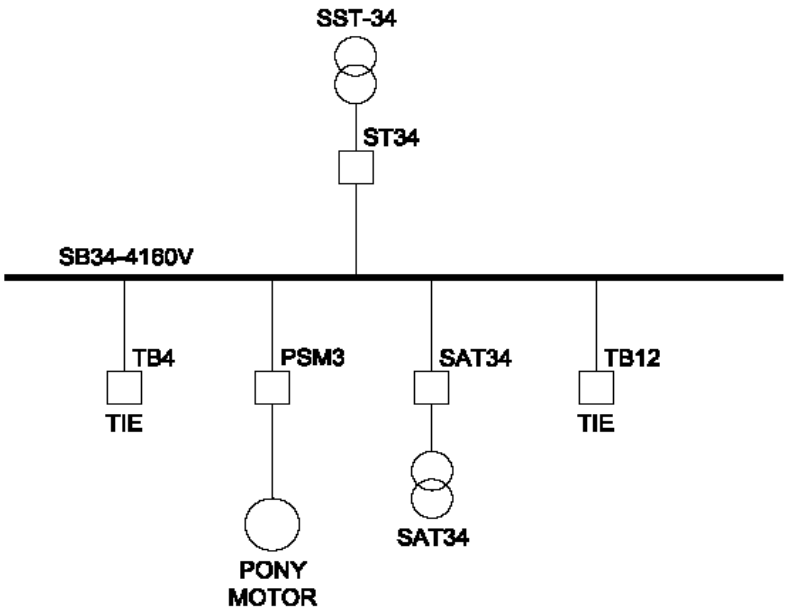



FIGURE 10-8 SB34 SWITCHGEAR

Unit Aux. Board UAB3 and Station Aux. Board SAB34 (600V) were manufactured by ITE and installed in 1980. The switchboards are complete with FPE 50H-2 incoming, tie and feeder breakers. All protection, synch, and control relays are original CGE electro-mechanical.

Unit Auxiliary Transformers, UAT3 and SAT34, were manufactured by FPE, and were installed in 1980. Both transformers are 1500/2000kVA, 4160:600/347V, ANAF, complete with tap-changer, +2@2.5%, Dy1, Z1=12%.

**Asset 271767 Unit 3 Turbine Supervisory System**

The Turbine Supervisory System was manufactured by Bently Nevada and installed in 1994. It is a type 3300 System, complete with TDXnet Transient Data Interface and Delta Manager.

Functionality of the Bently Nevada system has been transferred to the GE Speedtronic Mark V Turbine Governor System. There is a link to the DCS. Data acquisition is still part of the Bently Nevad system, and is transferred via a DDX link in the plant instrument shop. Machine protection is provided by the Mark V using information from the Bently Nevada, and is part of the Unit 3 mechanical protection, with the exception of the turbine vibration differential protection tripping, which is provided by the Bently Nevada system.

**Asset 301711 Unit 3 DCS**

The DCS, manufactured by Foxboro, is an Invensys system and was installed in 2004.

The Westinghouse panels housing the DCS were installed in the late 1990's, and new cabling was installed at that time. Original system was hard-wired, but was later updated to a Westinghouse system. Westinghouse could not support the system and it was then updated to Foxboro in 2004.

The process CPU → ZCP is set-up in the original enclosures, (Westinghouse Migration Cards). All I/O is tied-in to these for analog and digital functions.

The following system and programs being used are:

- IA series – Version 8.4.2
- IACC, Version 2.3.1 (Configuration Program)
- FoxView Version 10.2. Sept. 30, 2008 (Graphics Program)

Reference Foxboro Drawing D545390-SA-001 for system configuration.

**Asset 271769 Unit 3 Static Exciter**

Unit 3 Exciter is a Westinghouse system commissioned in 1979. Information, including drawings and bills of material are dated around 1978 and its technology is at least 20-30 years old.

### 10.1.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Replaced (DCS) | 2002-2003 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | 1988 |
| Synchronous Condensing End Date | Dec 2041 |
| Next Major Overhaul/Inspection | 2016 |

#### 10.1.3.3 Inspection and Repair History

Inspections and refurbishments are done on an ongoing basis and identified in Section 10.1.2.1 Description and in 10.1.2.3 Condition Assessment.

### 10.1.3.4 Condition Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. The basic DCS, protections, alarms associated with generators and auxiliaries are in good shape, but will over the next fifteen years need to be re-examined about every five years or so. The areas of most concern are the exciter and relay cabinets which have been identified by the plant as an area in need of upgrade. Some auxiliary systems such as hydrogen monitoring and generator temperature monitoring need replacement or refurbishment. The condition assessment for the various systems is presented in the following table.

**TABLE 10-15 CONDITION ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION&CONTROL | RELAY RM PROTECTION&CONTROL | N/A | 159 | 6 | Generator & Transformer & Auxiliary Protection and Metering Panels tests were satisfactory (2007). Some ingress of dust and foreign material. Testing is on a 6 year cycle (2013, 2017, 2025, etc.). | 10 | (30) | 10+ | 2041 | 2013 | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 160 | 6 | Installed in 1980. Protection, synch, and control relays are original electro-mechanical. Feeders Motor Protection Relays installed in 2009. All overhauled in 2007-2009 OK except corrective actions on CWW3 Jan, 2010. (status 80). and UAT-3 breaker, no date but status 90. Transformers UAT3 and SAT34 in 2007 showed reasonable tolerances. All 600V switchgear is applied within their ratings. | 10 | (30) | 10 | 2041 | 2007 | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 161 | 6 | Generator, turbine and boiler controls linked to the DCS with some original controls, indications and annunciations replaced. ASEA cabinets behind control room in hazardous state, with cabling so congested as to render the doors in the vertical sections unable to be closed. Potential for major failure and unit out of service for an indeterminate time. | 4 | (30) | 2 | 2041 | | | Yes | No | 1980/2007 |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 162 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 20 | 2041 | | | Yes | Yes | 1980/2004 |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | N/A | 163 | 6 | No recorded maintenance inspections have been carried out since installation. Generator oil leak evident from duct. | 4 | 200000 (30) | (10) | 2041 | | 2016 | No | No | 1980 |
| 1296 | 8193 | 8712 | 8715 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GEN. TRANSFORMER & AUX | GEN. TRANSFORMER & AUX | N/A | 164 | 6 | Good condition. | 4 | (30) | 10 | 2041 | | | No | No | 1980 |
| 1296 | 8193 | 8712 | 8716 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 165 | 6 | See details below. | 3a | (25) | 10 | 2041 | | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 8716 | 8717 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-3 | N/A | 166 | 6 | Tests in 2007 are satisfactory. Some ingress of dust and foreign material. | 3a | (30) | 10 | 2041 | 2013 | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 8716 | 8718 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT AUX. BOARD UAB-3 | N/A | 167 | 6 | Acceptable condition. | 3a | (30) | 10 | 2041 | | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 8716 | 8722 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | TURBINE AREA MCC TAB-34 | N/A | 168 | 6 | Acceptable condition. | 3a | (25) | 10 | 2020 | | | Yes | Yes | 1980 |
| 1296 | 8193 | 8712 | 8716 | 8724 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | BOILER AREA BAB-3 | N/A | 169 | 6 | Acceptable condition. | 3a | (25) | 10 | 2020 | | | Yes | Yes | 1980 |
| 1296 | 8193 | 8712 | 8750 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | 129 VDC | 170 | 6 | Installed in 1978. Last equipment check 04 Feb. 2010. | 3a | (25) | 10 | 2041 | 2010 | | No | No | 1980 |
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 171 | 6 | Installed in 2001. Last maintenance performed 04 Feb. 2010. Lightly loaded at 7kW. Panels and breakers are in good conditions, and if monitored, in a PM program, should provide service until 2041. | 3a | (20) | 10+ | 2041 | 2010 | | Yes | No | 2001 |
| 1296 | 8193 | 8712 | 8757 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | N/A | 172 | 6 | Installed in 2001. Last maintenance performed 04 Feb. 2010. Lightly loaded at 4kW. Panels and breakers are in good conditions, and if monitored, in a PM program, should provide service until 2041. | 3a | (20) | 10+ | 2041 | 2010 | | Yes | No | 2001 |
| 1296 | 8193 | 8712 | 8763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | 129 VDC | 173 | 6 | Installed in 1996. Replacement date 2021. Last equipment maintenance check was 04 Feb. 2010. | 3a | (25) | 10 | 2041 | 2010 | | Yes | No | 1996 |
| 1296 | 8193 | 8712 | 8763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | 258 VDC | 174 | 6 | Installed in 1996. Replacement date 2021. Last equipment maintenance check was 04 Feb. 2010. | 3a | (25) | 10 | 2041 | 2010 | | Yes | No | 1996 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | 258 VDC | 175 | 6 | Installed in 2001. Last equipment check 04 Feb. 2010. | 3a | (20) | 10 | 2041 | 2010 | | Yes | No | 2001 |
| 1296 | 8193 | 8712 | 271763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 176 | 6 | Normal inspections and PM every 10 years have not been done since 1995. Some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Some cables, power and control, are "thrown" into trays that have been convenient in the routings associated with the new installations. | 3a | (50) | (30) | 2041 | | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | N/A | 177 | 6 | No recent testing. | 4 | (50) | (20) | 2041 | | | No | No | 1980 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | N/A | 178 | 6 | No recent testing. | 4 | (50) | (20) | 2041 | | | No | No | 1980 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.1.3.5 Actions – Unit 3 Electrical and Control System Associated with Generators

Where a system is fully or partially required for synchronous condensing, it is included here. Based on the condition assessment, the following actions are recommended for the Unit 3 electrical and control system associated with generators:

**TABLE 10-16 RECOMMENDED ACTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | N/A | 231 | 6 | See details below. | 2011 | 2 |
| 1296 | 8193 | 8712 | 8698 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION&CONTROL | RELAY RM PROTECTION&CONTROL | N/A | 232 | 6 | Test Generator G3, Transformer T3 and Auxiliaries P&C Panels - next tests planned for 2011, 2017, 2023, etc. | 2011 | 1 |
| 1296 | 8193 | 8712 | 8698 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION&CONTROL | RELAY RM PROTECTION&CONTROL | N/A | 233 | 6 | Relay Room Protection & Control includes: Unit 3 Generator; Transformer, ST3/ST4 and Auxiliaries P & C; Generator and Transformer Protection Panels; Unit Transformer T3 and Unit #3 Protection Panel; Unit 3 Metering Panel; Transformer ST3/ST4 protection panel; and Two Blank Panels - Conduct a modernization study - refurbishing the old GE electro-magnetic relays versus multi-function relaying for periods to 2015, to 2020 then to 2041. Extend scope of existing Schweitzer SEL 300G from present ground fault monitoring to include all unit protection. Assess similar multi-function relay for back-up protection and consider for control, indication and annunciation functions an ABB Combiflex system. | 2011 | 2 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 234 | 6 | Include this Switchgear, 4160V/600V relaying in SB2 modernization study (5.3.2.28 IV) for the protection relays. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 235 | 6 | Overhaul all 4160V switchgear breakers. Consider with the availability of spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2013 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 236 | 6 | Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50 ft away, and is programmable for other types of breaker that might be used. | 2013 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 237 | 6 | Note: When the 4160V CWP pumps are taken out of service, cooling water needs will be taken up by new 600V pumps. It should also be considered to offset the upgrade of the Boiler Feed pumps to VFD's. See overhauling of breakers BFE3 and BFW3 above. | 2013 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 238 | 6 | Upgrade Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980. The switchboards are c/w FPE 50H-2 Incoming, Tie and Feeder Breakers. All protection, synch, and control relays are original CGE electro-mechanical. | 2012 | 1 |
| 1296 | 8193 | 8712 | 8704 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 239 | 6 | Carry out the NLH capital budget item to "Upgrade Unit 3 Relay Panels" in 2011, to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system for Unit 3. Investigations will need to be conducted at site, and discussions held with Foxboro to determine if the present DCS physical size can accommodate the changes, or if it will need to be extended. | 2011 | 2 |
| 1296 | 8193 | 8712 | 301711 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 240 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 8193 | 8712 | 8713 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | N/A | 241 | 6 | Conduct tests on the generator bus-duct, using the Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests, as outlined below, and to show comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. tests are as follows:<br>Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct. | 2011 | 2 |
| 1296 | 8193 | 8712 | 8713 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | N/A | 242 | 6 | Conduct generator bus-duct inspection tests using Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests and comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows:<br>Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct. | 2011 | 2 |

Table 10-16 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 8715 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GEN. TRANSFORMER & AUX | GEN. TRANSFORMER & AUX | N/A | 245 | 6 | No recommended actions. | | |
| 1296 | 8193 | 8712 | 8716 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 246 | 6 | No recommended actions. | | |
| 1296 | 8193 | 8712 | 8716 | 8717 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-3 | N/A | 247 | 6 | No recommended actions. | | |
| 1296 | 8193 | 8712 | 8716 | 8718 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT AUX. BOARD UAB-3 | N/A | 248 | 6 | No recommended actions. | | |
| 1296 | 8193 | 8712 | 8716 | 8722 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | TURBINE AREA MCC TAB-34 | N/A | 249 | 6 | Refurbish selective MCC elements. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8716 | 8724 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | BOILER AREA BAB-3 | N/A | 250 | 6 | Monitor condition and refurbish as required from spares. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8750 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 251 | 6 | Replace Unit 3, 129VDC Battery Charger 1. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8750 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 252 | 6 | Replace Unit 3, 129VDC Battery Charger 2. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8750 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 253 | 6 | Replace Unit 3, 258VDC Distribution Panel and breakers. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8751 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 254 | 6 | No specific actions required. | | |
| 1296 | 8193 | 8712 | 8751 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 255 | 6 | Optimize in conjunction with UPS1, UPS2 and UPS4 the possible replacement of the units with two parallel units for requirement for inverters from 2020 to 2041. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8757 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | N/A | 256 | 6 | No specific actions required. | | |
| 1296 | 8193 | 8712 | 8757 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | N/A | 257 | 6 | Optimize in conjunction with UPS1, UPS2 and UPS4 the possible replacement of the units with two parallel units for requirement for inverters from 2020 to 2041. | 2012 | 2 |
| 1296 | 8193 | 8712 | 8763 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | N/A | 258 | 6 | No action is required. | | |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | N/A | 259 | 6 | No action is required. | | |
| 1296 | 8193 | 8712 | 271763 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 260 | 6 | Clean raceways, trays and cables to be tested by a crew of specialized hazardous area cleaners before any inspections or tests are carried out. | 2011 | 3 |
| 1296 | 8193 | 8712 | 271764 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | N/A | 261 | 6 | Test selected control cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. | 2011 | 3 |
| 1296 | 8193 | 8712 | 271765 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | N/A | 262 | 6 | Test selected power cables - 4160V, 600V cables selected based on how the distribution will be affected post SC conversion, especially if the cables are required to be re-run.<br>Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.<br>Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable. | 2011 | 3 |

### 10.1.3.6 Risk Assessment

Where a system is fully or partially required for synchronous condensing, it is included here. The risk assessment associated with the Unit 3 electrical and control system associated with generators, both from a technological perspective and a safety perspective, is illustrated below in Table 10-17.

**TABLE 10-17 RISK ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8712 | 0 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | N/A | 200 | | See detail below. | | | | | | | | | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION&CONTROL | RELAY RM PROTECTION&CONTROL | N/A | 201 | 6 | Electrical fault, mechanical fault, ops error. | 5+ | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. | Current inspection and maintain. |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 202 | 6 | Electrical fault, mechanical fatigue, ops error. | (5) | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 203 | 6 | Electrical fault, mechanical fatigue, ops error. | 2 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation, damage to unit. | Current inspection and maintain. |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 204 | 6 | Electrical fault, ops error. | 20 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Maintain. |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | N/A | 205 | 6 | Electrical fault. | (10) | None | 3 | C-D | Medium/ High | 3 | C-D | High | Loss 1 unit generation, damage to unit. | Current inspection and maintain. |
| 1296 | 8193 | 8712 | 8715 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GEN. TRANSFORMER & AUX | GEN. TRANSFORMER & AUX | N/A | 206 | | Regulatory PCB. | 3 | 2013 PCB Reg likely. | 3 | C | Medium | 2 | B | Low | Oil spill/PCB contamination. | Replace per regulations when required. |
| 1296 | 8193 | 8712 | 8716 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 207 | | Electrical fault, mechanical fatigue, controls fault, ops error. | 20 | None | 1 | C | Medium | 2 | B | Low | Loss 1 unit generation. Damage to unit. | Inspect and test per current maintenance program. |
| 1296 | 8193 | 8712 | 8716 | 8717 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-3 | N/A | 208 | | See details below. | 5 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8716 | 8718 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT AUX. BOARD UAB-3 | N/A | 209 | | Electrical fault, mechanical fatigue, ops error. | 10 | None | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8716 | 8722 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | TURBINE AREA MCC TAB-34 | N/A | 210 | | Not addressed in detail - electrical failure. | 5 | None | 3 | B | M | 3 | A | Low | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8716 | 8724 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | BOILER AREA BAB-3 | N/A | 211 | | Mechanical/electrical failure. | 5 | None | 3 | B | M | 4 | A | Low | Loss of part of 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8750 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 214 | 6 | Electrical or chemical fault. | 10 | None | 3,1 | B-C | Medium, Low | 1 | B | Low | Unit damage on fail to safe shutdown. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 215 | 6 | Electrical fault. | 10+ | None | 3,1 | B | Medium, Low | 1 | B | Low | Unit damage on fail to safe shutdown. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8757 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | N/A | 216 | 6 | Electrical fault. | 10+ | None | 3,1 | B | Medium, Low | 1 | B | Low | Unit damage on fail to safe shutdown. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | N/A | 217 | | Electrical failure. | 10 | None | 1 | B | Low | 1 | C | Low | Regular test and maintenance. | |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | N/A | 218 | | Electrical failure. | 10 | None | 1 | B | Low | 1 | C | Low | Regular test and maintenance. | |
| 1296 | 8193 | 8712 | 271763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 219 | | Electrical short. | (30) | None | 1 | C | Low | 1 | C | Low | PM inspections. | |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | N/A | 220 | 6 | Electrical fault. | (20) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage. | Test indicative number. |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | N/A | 221 | 6 | Electrical fault. | (20) | None | 2 | B-C | Low | 2 | B-C | Low | Loss of up to 1 unit generation. Equipment/unit damage. | Test indicative number. |
| 1296 | 8193 | 8712 | 309896 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | 600 V MELTRIC PLUGS | 600 V MELTRIC PLUGS | N/A | 222 | | Not addressed. | 30 | None | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |

### 10.1.3.7 Life Cycle Curve and Remaining Life

Figures 10-9 and 10-10 below illustrate the life cycle curve for the Unit 3 electrical and control system associated with the Unit 3 generators. Several curves are required to represent the various elements. They have been broken into two parts – the electrical and control systems (MCC's, relays, breakers, TSI, DCS) and those primarily associated with batteries and chargers. The curves are plots of current and projected years in service on the y-axis versus calendar year on the x-axis. Age in-service due to either aging or obsolescence is more an issue than unit operating hours. Vertical lines represent bands of nominal years of in-service life for different in service dates. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

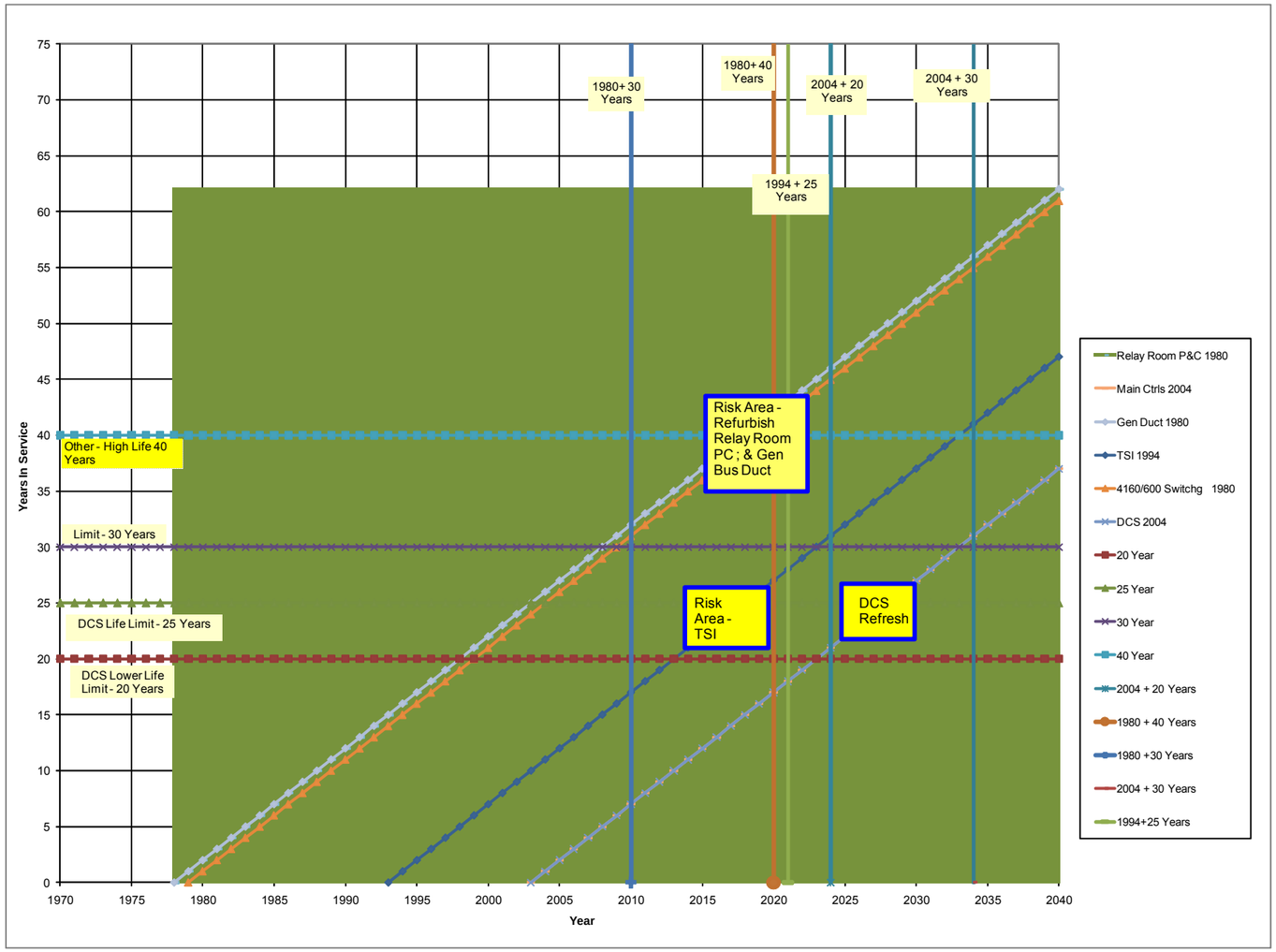



**FIGURE 10-9 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS (MCC'S, RELAYS, BREAKERS, TSI, DCS)**

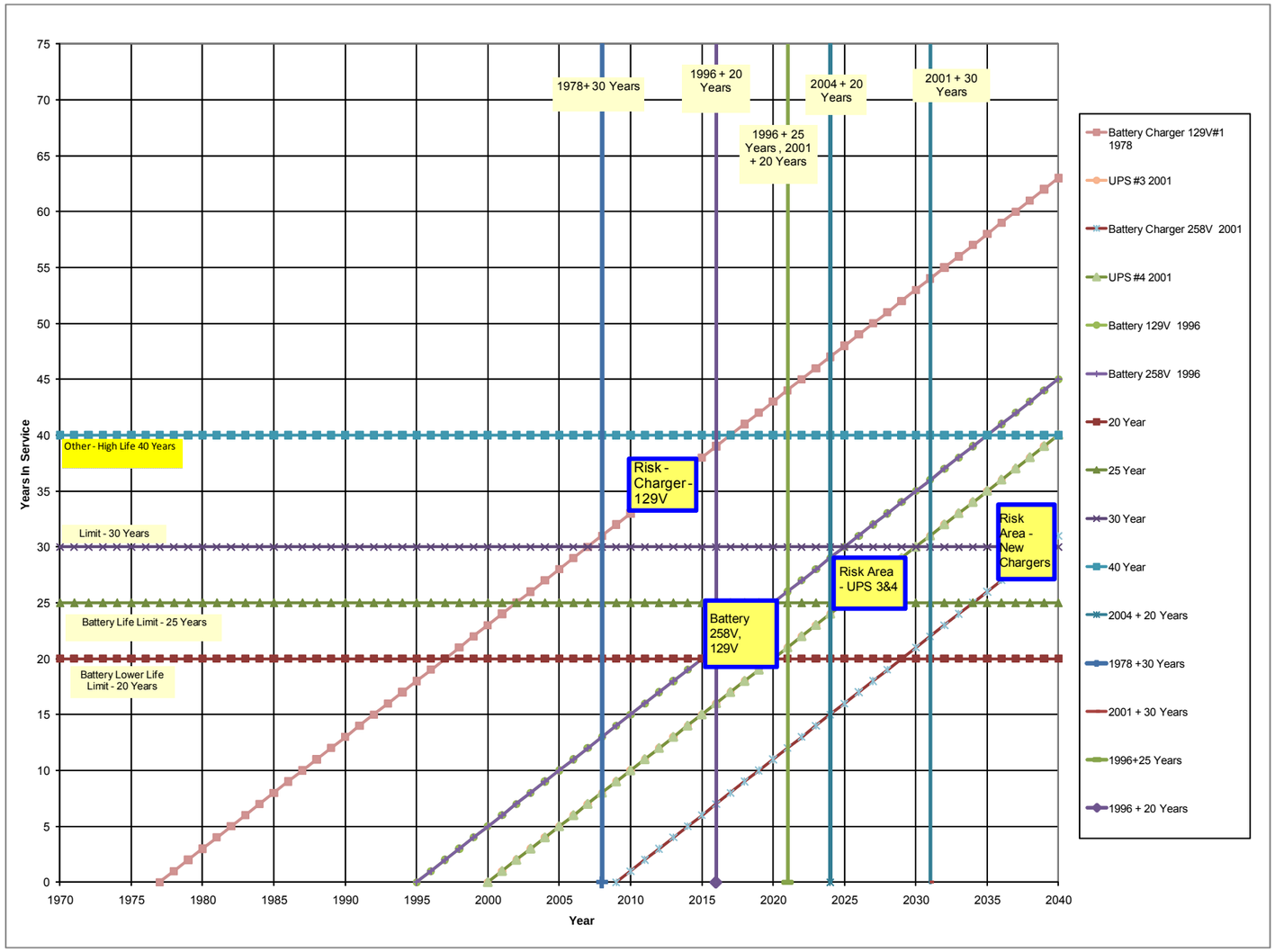



**FIGURE 10-10 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS (BATTERIES AND CHARGERS)**

The curves indicate that the remaining life (RL) of much of the equipment does not exceed the desired life (DL) for generation of 2020 and for synchronous condensing of 2041, without extensive refurbishment or replacement. This is well illustrated by the highlighted risk areas which highlights that many original MCC's and relays as well as the TSI are in need or replacement or extensive refurbishment in the very near term. The risk figures also illustrate that some equipment (DCS, batteries, and chargers) will require replacement or refurbishment in the 2020+ period.

### 10.1.3.8 Level 2 Inspection Requirements and Costs

Where a system is fully or partially required for synchronous condensing, it is included here. Recommended Level 2 analyses are identified in the following table.

**TABLE 10-18 LEVEL 2 INSPECTION – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | None | 185 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | None | 186 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | None | 187 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | None | 188 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | None | 189 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | Generator Bus-duct and Connections | 190 | 6 | Conduct complete generator bus-duct partial maintenance inspection and tests on the U1 bus-duct:<br>Low Resistance Test : Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor).<br>Insulation Resistance Test: Measure phase-to-phase and phase-to-ground insulation resistance, must be > 100Mohm per 1000 ft. of bus-duct. | 2011 | 1 | $15 |
| 1296 | 8193 | 8712 | 8715 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GEN. TRANSFORMER & AUX | GEN. TRANSFORMER & AUX | Unit Auxiliary Transformers, UAT3 and SAT34, | 191 | 6 | Inspect and test transformers UAT3 and SAT34 and 50H-2 air circuit breakers. Check the bussing. Inspection/testing of transformers - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. | See Transformers | 1 | |
| 1296 | 8193 | 8712 | 8716 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | None | 192 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8716 | 8717 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-3 | None | 193 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8716 | 8718 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT AUX. BOARD UAB-3 | None | 194 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8716 | 8722 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | TURBINE AREA MCC TAB-34 | None | 195 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8750 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | None | 198 | 6 | No Level 2 inspections or testing is required. | | | |

Table 10-18 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | None | 199 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8757 | 0 | 0 | 3 | LECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | None | 200 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | None | 201 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8763 | 9.9E+07 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | None | 202 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 271763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 203 | 6 | | | | |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 204 | 6 | Inspection and test selected control cables: Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). | 2011 | 3 | $7 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | Units 1, 2, 3 Cable Raceways, Control Cables, Power Cables | 205 | 6 | Inspect/test selected power (4160V, 600V) cables: Low Resistance Test: Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor).<br>- Insulation Resistance Test: Apply a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Phase-to-phase and phase-to-ground insulation resistance tests, must be >100Mohm per 1000 ft. | 2011 | 3 | $10 |
| 1296 | 8193 | 8712 | 309896 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | 600 V MELTRIC PLUGS | 600 V MELTRIC PLUGS | None | 206 | 6 | No Level 2 inspections or testing is required. | | | |

### 10.1.3.9 Capital Projects

Where a system is fully or partially required for synchronous condensing, it is included here. The suggested typical capital enhancements include:

**TABLE 10-19 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 ELECTRICAL AND CONTROL SYSTEM ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | N/A | 156 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 157 | 6 | 3 | Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 158 | 6 | 3 | Include this switchgear, 4160V/600V relaying in SB2 modernization implementation for the protection relays. | 2012 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 159 | 6 | 3 | Overhaul all 4160V switchgear breakers. Use spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become “spare” but in good condition. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 160 | 6 | 3 | Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement as required Eaton Electrical Remote racking device (RPR2) for remote racking. Note: When the 4160V CWP pumps are taken out of service, cooling water needs will be taken up by new 600V pumps. It should also be considered to offset the upgrade of the Boiler Feed pumps to VFD’s. See overhauling of breakers BFE3 and BFW3 above. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 161 | 6 | 3 | Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980. The switchboards are c/w FPE 50H-2 Incoming, tie and feeder breakers. All protection, synch, and control relays are original CGE electro-mechanical. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 162 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 163 | 6 | 3 | Upgrade Unit 3 Relay Panels to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system including changes to present DCS physical size to accommodate the changes. | 2014 | 1 |

Table 10-19 Cont’d

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DCS | DCS | N/A | 164 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | N/A | 165 | 6 | 3 | None planned, but may result from tests. | | |
| 1296 | 8193 | 8712 | 8715 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GEN. TRANSFORMER & AUX | GEN. TRANSFORMER & AUX | N/A | 166 | 6,5 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8716 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT SERVICE POWER SYSTEM | N/A | 169 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8716 | 8717 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT BOARD UB-3 | N/A | 170 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8716 | 8718 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | UNIT AUX. BOARD UAB-3 | N/A | 171 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8716 | 8722 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | TURBINE AREA MCC TAB-34 | N/A | 172 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8716 | 8724 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | BOILER AREA BAB-3 | N/A | 173 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8750 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY CHARGERS | BATTERY CHARGERS | N/A | 174 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 175 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | N/A | 176 | 6 | 3 | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement. | 2012 | 1 |
| 1296 | 8193 | 8712 | 8757 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 4 INVERTER | UPS 4 INVERTER | N/A | 177 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY BANKS | N/A | 178 | 6 | 3 | No action is required. | | |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | N/A | 179 | 6 | 3 | Replace Unit 3, 129VDC battery charger 1. | 2012 | 1 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | N/A | 180 | 6 | 3 | Replace Unit 3, 129VDC battery charger 2. | 2012 | 1 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | N/A | 181 | 6 | 3 | Replace Unit 3, 258VDC distribution panel and breakers. | 2012 | 1 |
| 1296 | 8193 | 8712 | 271763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | N/A | 182 | 6 | 3 | Install any new cable installations on new tray, and in accordance with the applicable codes. | 2011 | 1 |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | N/A | 183 | 6 | 3 | Install any new cable installations on new tray, and in accordance with the applicable codes. | 2011 | 1 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | N/A | 184 | 6 | 3 | Install any new cable installations on new tray, and in accordance with the applicable codes. | 2011 | 1 |

### 10.1.4 Asset 271678 – Unit 3 Cooling Water Systems Associated with Generators

(Detailed Technical Assessment in Working Papers, Appendices 8 and 11)

Equipment Scope:

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8645 #3 Unit Generation Services |
| Sub-Systems: | 271678 #3 CW System |
| | 8691 #3 T/gen Water Cooling |
| | 8291 #3 Gen Service Cooling |
| Components: | 8649 #3 CW Travelling Screens East |
| | 8650 #3 CW Travelling Screens West |
| | 8658 #3 CW Pump East |
| | 8659 #3 CW Pump West |
| | 8647 #3 CW Intake |
| | 8676 #3 CW Discharge to Outfall |
| | 8691 #3 General Service Water |
| | 8262 #3 Turbine Generator Cooling Water |

#### 10.1.4.1 Description

The items examined were limited to those required to achieve the 2041 synchronous condensing end date:

- The main pumphouse sea water intake, traveling screens, and general service water system;
- Heat exchange system;
- Seawater discharge system; and
- Electrical and control requirements.

**Asset 271678 Circulating Water (CW) Pump and Screens Systems**

Circulating water (CW) systems servicing Unit 3 consist of two 50% CW vertical turbine pumps, travelling screens, and associated wash pumps and systems. The primary function of the CW system is to provide condenser cooling water, but also cooling water for other closed loop systems. It is necessary that the

CW system operate efficiently in order maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

**Asset 8262 TG Auxiliary Cooling Water System**

Sea water cooling is used for the Turbine Generator (TG) auxiliary cooling water system which is required for synchronous condensing operation. Sea water can currently be supplied by a sump pump and dedicated line from the Stage 2 pumphouse (Unit 4 CW pump pit), from a water take-off from the Stage 2 pumphouse circulating water pumps, or from an interconnection with the Units 1 and 2 cooling water systems. Typically, when only Unit 3 is running in synchronous condensing mode, the smaller sump pump and dedicated line from the Stage 2 pumphouse is used.

For long term synchronous condensing operation to 2041, the intent is to supply seawater from a small, permanent pump arrangement similar to the temporary system.




**FIGURE 10-11 DEDICATED SEAWATER COOLING WATER LINE FOR UNIT 3 SYNCHRONOUS CONDENSING GT AUXILIARY COOLING WATER**

### 10.1.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | 1986 |
| Synchronous Condensing End Date | Dec 2041 |
| Last Major Overhaul/Inspection | Not identified |
| Next Major Overhaul/Inspection | Not Identified |

### 10.1.4.3 Inspection and Repair History

**CW Travelling Screens:** The Unit 3 CW travelling screens have not been refurbished and should be within the next 5 years. The external casings have some corroded parts, but nothing that appears to impair current or short term performance.

**CW Wash Water Pumps and Motors:** An external inspection of the CW wash pumps and motors indicated that they have extensive corrosion but were running at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**CW Pumps:** CW pumps servicing Unit 3 are performing fairly well. Reports outlining the condition of the pumps were not available, but interviews suggest that regular maintenance has been ongoing and the units should be able to meet 2015 and 2020 timelines with continued maintenance. Major pump overhauls are scheduled on a twelve year cycle, as indicated in Table 10-20 below.

**TABLE 10-20 MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

A temporary CW pump is being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for synchronous condensing operation. There are also interconnections between the Units 1, 2, and 3 CW systems that allow them to provide back-up for this purpose if necessary.

**CW Pump Motors:** Motors are electrically tested every year (as a component of the PM process).

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves and fittings from the CW pump discharge to the inlet of the 64 inch concrete piping that is installed underground to the Unit 3 condenser has generally experienced significant corrosion and some patching of the system has been done. It requires a Level 2 inspection and possibly replacement or refurbishment.

**Cooling Water System Intake & Discharge:** The 36 inch and 64 inch CW intake and discharge concrete piping that is installed underground to the Unit 3 condenser has periodically been dewatered and inspected by plant staff, although not in the last five years. Specific corrosion, spalling, cracks or fractures were not identified and patching of the system has not been done. There have been no obvious issues with the systems, although no detailed engineering evaluations and NDE work has been undertaken.

PM inspections are planned going forward on a three year cycle, as per schedule below in Table 10-21.

**TABLE 10-21 PM INSPECTIONS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 10.1.4.4 Condition Assessment

The condition assessment of the Unit 3 cooling water system associated with generators is illustrated below in Table 10-22.

**TABLE 10-22 CONDITION ASSESSMENT – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | N/A | 135 | 12 | Piping is pitted. Pumps and motors are original. Heat exchangers appear in good condition. Heat exchangers are cleaned and checked for leaks annually, and are cathodically protected and a closed cooling system corrosion inhibitor used. No issues had been encountered with the heat exchangers. No inspection or maintenance data was available. | 4 | (30) | 10 | 2041 | 2011 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Sea Water Piping | 136 | 11,15 | Sea Water piping 18" lines and associated valving is original equipment for all units. No condition data but no significant issues identified. Piping and valves have external corrosion and pitting, but rate seems not to be rapid. | 4 | (30) | (10) | 2041 | 2011 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 8262 | 9658 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP EAST | N/A | 137 | 11,15 | Pumps and motors are original equipment and are in relatively poor condition - primarily due to age and use. | 4 | (30) | 10 | 2041 | 2012 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 8262 | 9660 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP WEST | N/A | 138 | 11,15 | Pumps and motors are original equipment and are in relatively poor condition - primarily due to age and use. | 4 | (30) | 10 | 2041 | 2012 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 139 | 11,15 | PVC piping can have lifetimes of up to 100 years. The current pipe is less than 20 years old. No difficulties identified or expected. | 4 | (50) | 20 | 2041 | | | Yes | Yes | 1990 |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Intake Structure and Foreay | 150 | 11 | No recent underwater inspections of intake structures or bay, but surface visual check looked good. There is no reason to expect any kind of aggressive attack. | 4 | (60) | (20+) | 2041 | | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Pit, Stoplogs and Discharge | 151 | 11 | No recent underwater inspections of pit, stoplogs or outfall structures. | 4 | (60) | (20+) | 2041 | | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | N/A | 152 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2012 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | N/A | 153 | 11 | Internals in good condition after major upgrade within the last five to ten years. External casings and auxiliaries have some corrosion. | 4 | (20) | (10) | 2041 | 2012 | | No | No | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8823 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. SCREEN WASH SYSTEM | N/A | 154 | 11 | Significant corrosion,. Likely near end of life. | 3a | 200000 (30) | 5 | 2041 | | | No | No | 1980 |
| 1296 | 8193 | 8645 | 271678 | 279782 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | SYNCH CONDENSER AUX CW SYSTEM | N/A | 155 | 11 | Recent addition rigged in temporary fashion. No issues with performance. | 3a | (30) | 10 | 2041 | | | No | No | 1990 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.1.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 cooling water systems associated with generators:

**TABLE 10-23 RECOMMENDED ACTIONS – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | N/A | 202 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Aux Cooling Water Piping | 203 | 8 | Clean and coat remaining auxiliary cooling water piping. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | TG Piping | 204 | 8 | Perform representative Level 2 pipe thickness checks on seawater intake and discharge piping. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Aux Cooling Water Piping | 205 | 8 | Perform Level 2 on auxiliary Cooling Pipes during next five years. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Aux Cooling Water Pumps | 206 | 8 | Replace Unit 3 auxiliary cooling water pumps and motors in next five years. | 2012 | 1 |
| 1296 | 8193 | 8645 | 8262 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Aux Cooling Water Pumps | 207 | 8 | Perform Level 2 on auxiliary cooling heat exchangers during next five years. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 9658 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP EAST | N/A | 208 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8262 | 9660 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP WEST | N/A | 209 | 8 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 8193 | 8645 | 8691 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 210 | 12 | Continue current condition monitoring and heat exchanger servicing. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8647 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | N/A | 223 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplog. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8649 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | N/A | 224 | 11 | Assess Unit 3 travelling screen refurbishment requirements. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8650 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | N/A | 225 | 11 | Assess Unit 3 travelling screen refurbishment requirements. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | N/A | 226 | 11 | Perform an underwater inspection of intake and outfall structures - including areas such as stoplog. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8823 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 227 | 11 | Clean and refurbish. | 2011 | 3 |
| 1296 | 8193 | 8645 | 271678 | 279782 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | SYNCH CONDENSER AUX CW SYSTEM | N/A | 228 | 11 | Implement a permanent system. | 2012 | 2 |

### 10.1.4.6 Risk Assessment

The risk assessment associated with the Unit 3 cooling water systems associated with generators, both from a technological perspective and a safety perspective, is illustrated below in Table 10-24.

**TABLE 10-24 RISK ASSESSMENT– UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | TURBINE/GENERATOR WATER COOLING SYSTEM | Unit 3 ACW Ht Exch | 171 | 8 | Corrosion, mechanical failure/pluggage. | 20+ | None | 1 | A | Low | 1 | A | Low | Sparing, minimal. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | TURBINE/GENERATOR WATER COOLING SYSTEM | Unit 3 ACW Piping | 172 | 8 | Corrosion, mechanical failure. | 20+ | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | TURBINE/GENERATOR WATER COOLING SYSTEM | Unit 3 Seawater Piping | 173 | 8 | Corrosion mechanical failure. | (10) | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | TURBINE/GENERATOR WATER COOLING SYSTEM | Unit 3 Seawater Piping – Synch Condensing | 174 | 8 | Mechanical failure. | 10+ | None | 1 | A | Low | 1 | A | Low | Sparing, minimal – retain at least 1 CW capable supply. | Maintain spare capability. Inspect and maintain. |
| 1296 | 8193 | 8645 | 8262 | 9658 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | T/G COOLING WATER PUMP EAST | Unit 3 ACW Pump/Motor | 175 | 8 | Mechanical or electrical failure. | 5 | None | 1 | A | Low | 1 | A | Low | Sparing, minimal. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 8262 | 9660 | 0 | 3 | UNIT GENERATION SERVICES | TURBINE/GENERATOR WATER COOLING SYSTEM | T/G COOLING WATER PUMP WEST | Unit 3 ACW Pump/Motor | 176 | 8 | Mechanical or electrical failure. | 5 | None | 1 | A | Low | 1 | A | Low | Sparing, minimal. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Pump/Motor Failure | 177 | 12 | Mechanical or electrical failure. | 10+ | None | 1 | A | Low | 1 | A | Low | Minimum. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Ht Exch Failure | 178 | 12 | Mechanical failure/pluggage. | 10+ | None | 1 | A | Low | 1 | A | Low | Seawater contamination (unlikely). | Inspect and maintain. |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | GSW Piping Failure | 179 | 12 | Mechanical failure. | 20+ | None | 1 | A | Low | 1 | A | Low | Leak and short duration impact. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Unit #3 Intake Structure | 192 | 17 | Structural cracking; steel corrosion. | 20+) | None | 1 | B | Low | 1 | A | Low | Structural failure requiring shutdown. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | Unit #3 Travelling Screens | 193 | 11 | Corrosion-internal/ext. | 5+ | None | 2 | B | Low | 2 | A | Low | Condenser plugging. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | Unit #3 Travelling Screens | 194 | 11 | Corrosion-internal/ext. | 5+ | None | 2 | B | Low | 2 | A | Low | Condenser plugging. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Unit #3 CW Outfall Piping | 195 | 11 | Concrete cracking. | (20+) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8823 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 196 | | Mechanical failure. | 2 | None | 3 | A | Low | 3 | A | Low | Unit performance loss. | Inspect, refurbish, replace. |
| 1296 | 8193 | 8645 | 271678 | 279782 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | SYNCH CONDENSER AUX CW SYSTEM | N/A | 197 | | Mechanical/electrical failure. | (20) | None | 1 | B | Low | 1 | B | Low | Loss of unit for short period. | Inspect and maintain. |

### 10.1.4.7 Life Cycle Curve and Remaining Life

Figure 10-12 below illustrates the life cycle curve for the various elements of the Unit 3 CW systems associated with generators. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits for various components. It has horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Data specific to the intake and outfall structures were not sufficient to include them, but they are not expected to be an issue (perhaps the condition of some operational equipment such as stoplogs or their supports). Data specific to the pumps and motors for the general service cooling water and the turbine generator cooling water are also not presented as they are relatively new and/or modest equipment elements. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

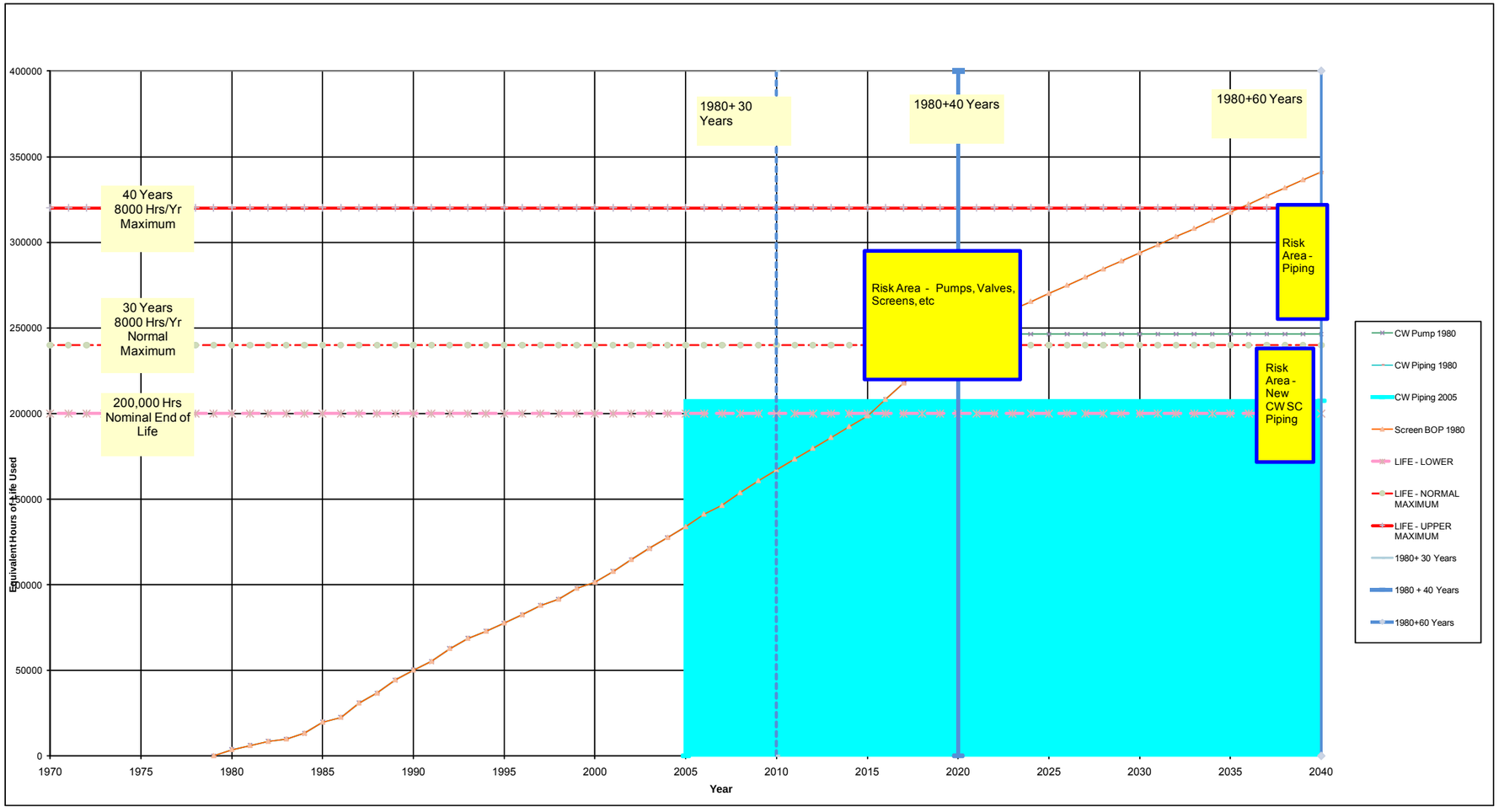



**FIGURE 10-12 LIFE CYCLE CURVE – UNIT 3 WATER SYSTEMS ASSOCIATED WITH GENERATORS**

The curve indicates that the remaining life (RL) of most elements of the Unit 3 cooling water systems associated with generators is sufficient to reach the end date of 2020 for generation, but not the 2041 desired life (DL) end date for synchronous condensing. The CW pumps and associated equipment are the primary nearer term issues highlighted by the risk boxes. The actual end date and remaining life will become clearer through the series of ongoing routine inspections that forms part of the plant's PM program and the Level 2 inspections recommended in the report. The intake and outfall structures and associated sub-components should be added as a result of a Level 2 inspection.

### 10.1.4.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the following Level 2 analyses are recommended.

**TABLE 10-25 LEVEL 2 INSPECTION – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 0 | 0 | 0 | 3 | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | None | 162 | | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Seawater intake and discharge piping | 163 | 8 | Perform representative Level 2 pipe thickness checks. | 2011 | 2 | $6 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | AC water piping | 164 | 8 | Thickness spot checks within 5 years. | 2011 | 2 | $6 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Ht Exch | 165 | 8 | AC Water Ht Exchangers shell and tubes within 5 years. | 2011 | 2 | $6 |
| 1296 | 8193 | 8645 | 8262 | 9658 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP EAST | None | 166 | 8 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8645 | 8262 | 9660 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP WEST | None | 167 | 8 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | None | 168 | 12 | None planned. | | | |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | CW intake and discharge structures and piping | 177 | 11 | Inspections – diver visual inspection. | 2011 | 2 | $30 |
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | None | 178 | 11 | No Level 2 inspections or testing is required. | 2011 | | |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | None | 179 | 11 | No Level 2 inspections or testing is required. | 2011 | | |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | CW intake and discharge structures and piping | 180 | 11 | Inspections – diver visual inspection. | 2011 | 2 | $30 |
| 1296 | 8193 | 8645 | 271678 | 8823 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | None | 181 | 11 | No Level 2 inspections or testing is required. | 2011 | | |
| 1296 | 8193 | 8645 | 271678 | 279782 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | SYNCH CONDENSER AUX CW SYSTEM | None | 182 | 11 | No Level 2 inspections or testing is required. | 2011 | | |

### 10.1.4.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 cooling water systems associated with generators include:

**TABLE 10-26 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 COOLING WATER SYSTEMS ASSOCIATED WITH GENERATORS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 0 | 0 | 0 | 3 | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | UNIT GENERATION SERVICES | N/A | 134 | | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | N/A | 135 | 8 | 3 | Clean and coat AC water pipes. | 2012 | 1 |
| 1296 | 8193 | 8645 | 8262 | 9658 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP EAST | N/A | 136 | 8 | 3 | Replace Unit 3 AC water pumps and motors. | 2014 | 1 |
| 1296 | 8193 | 8645 | 8262 | 9660 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP WEST | N/A | 137 | 8 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 8691 | 0 | 0 | 3 | UNIT GENERATION SERVICES | GENERAL SERVICE COOLING | GENERAL SERVICE COOLING | N/A | 138 | 12 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | Intake structure and pit | 148 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | N/A | 149 | 11 | 3 | Refurbish Unit 3 CW travelling screen. | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | N/A | 150 | 11 | 3 | Refurbish Unit 3 CW travelling screen. | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | Outfall structure, pit, stoplogs | 151 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8823 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SCREEN WASH SYSTEM | N/A | 152 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 279782 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | SYNCH CONDENSER AUX CW SYSTEM | N/A | 153 | 11 | 3 | No capital required. | | |

## 10.2 Unit 3 – Lower Priority Systems

### 10.2.1 Asset 8336 – Unit 3 Boiler System

(Detailed Technical Assessment in Working Papers, Appendices 29, 30, 34)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8336 #3 Boiler Plant |
| Sub-Systems: | 8337 #3 Boiler Structure |
| | 8339 #3 Boiler F.W. & Sat. Steam |
| | 8359 #3 Boiler Superheats Reheat |
| Components: | 8340 #3 Economizer, tubing and headers |
| | 8339 #3 Linking piping (boiler internals l) |
| | 8351 #3 Furnace water circuit<br>8344 #3 Steam drum<br>8351 #3 Downcomers and feeder piping as required<br>8351 #3 Lower Waterwall headers<br>8351 #3 Waterwall tubing<br>8351 #3 Upper Waterwall headers, and riser piping as re |
| | 8360 #3 Superheater; headers and tubing |
| | 8384 #3 Reheater; headers and tubing |
| | 8339 #3 Safety Valves |
| | 8372 #3 Boiler Main Steam lines |
| | 8273 #3 Boiler Stop Valve |
| | 8460 #3 Furnace combustion systems; burners, fans, air |
| | 8337#3 Furnace structural, hangers and casing |
| | 8494 #3 Boiler Blowdown Tank |

#### 10.2.1.1 Description

The Unit 3 boiler is a Babcock and Wilcox natural circulation, single reheat, pressurized unit of 1980 vintage design .The boiler is designed for an output of 150 MW with a maximum steam flow rate of 135 kg/s (1,072,000 lbs/hr), at 13 MPag (1890 psig) and 541°C (1005 °F) with an inlet feedwater temperature of 246 °C (476 °F). The reheat steam flow was designed at 125 kg/s (993,000 lbs/hr) with an inlet temperature of 282 °C (539 °F) and an outlet temperature of 538 °C (1005 °F). Unit 3 boiler was commissioned in 1979.

The system includes:

- Economizer, tubing and headers
- Linking piping (boiler internal)
- Furnace water circuit:
  - Steam drum;
  - Downcomers and feeder piping;
  - Lower Waterwall headers;
  - Waterwall tubing; and
  - Upper Waterwall headers and riser piping;
- Superheater headers and tubing;
- Reheater headers and tubing;
- Safety valves;
- Furnace combustion systems: burners, fans, and air heaters;
- Furnace structural, hangers and casing; and
- Boiler Main Steam lines
- Boiler Stop Valve
- Boiler blow down tank.

#### 10.2.1.2 History

| | **Unit 3** |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Major Inspection/Maintenance Repair | Annual May to Sep on all units |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |
| | |
| Max Hours Ops – 1986 to Dec 2009 | 113 |
| Max Hrs - 1986 to Dec 2015 | 142 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 164 |

| | |
|---|---|
| Max Hours Ops – 2007/8 to Dec 2009 | 5 |
| Max Hrs – 2007/8 to Dec 2015 | 35 |
| Max Hrs – 2007/8 to Gen End Date Dec 2020 | 59 |

#### 10.2.1.3 Inspection and Repair History

**Asset 8340 Economizer**

As per part of routine non destructive evaluation (NDE) inspections, ultrasonic thickness (UT) measurement readings are taken at specified locations on the economizer inlet and outlet headers. However, inspection results were not available. The following discussion summarizes the significant inspections and repairs completed on the economizer section servicing Unit 3.

During the 2002 outage, the economizer inlet header was opened for debris removal and internal visual inspection using boroscope. Loose debris was found in the inlet header and was removed. The findings of internal inspection are not mentioned in the outage report.

During the 2004 outage, a thermocouple was installed on the inlet header near the inlet pipe. However, it appears from the outage reports that the thermocouple has not been commissioned yet.

During 2008 outage, an angle beam UT inspection of the first 3 inches of twelve tubes at the economizer inlet header was carried out. The first two and last two rows were selected along with other tubes at random. No defects were found.

During the field walkdown by AMEC, it was observed that the economizer link piping did not have any pipe support.

**Asset 8351 Waterwall Headers, Downcomers, and Lower and Upper Feeder Tubes**

Exterior visual inspections of the lower and upper waterwall headers are carried out during the boiler outage inspections. Lower waterwall headers were opened a number of times for debris removal after boiler repairs. There were no internal inspections done for checking for ligament cracking or cracking at other locations.

During 2008 outage, all eight of the lower waterwall headers were opened for inspection and cleaning after completion of the boiler chemical clean. In the two east/west headers, there was a circumferential weld at the handhole location. The inside of the weld across from the handhole in both headers appeared to have poor fusion at the root and it was considered to be superficial.

UT measurements were taken on the waterwall circuit feeder and riser tubes. During 2004 outage, four of the 5 inch diameter riser (upper feeder) tubes were inspected with angle beam UT method to look for cracking. No defect was found.

**Asset 8344 Steam Drum**

All the accessible internal seam and nozzle welds are inspected using the Wet Fluorescent Magnetic Particle Examination (WFMT) method during every outage. A varying degree of magnetite layer was observed during outage inspections. Although slight pitting was observed but not active, it is not considered a pressure integrity issue for the steam drums.

**Asset 8351 High Temperature Headers and Piping**

During annual maintenance outages, Magnetic Particle Inspection (MPI) is carried out on the selective tube to header welds on the superheater and reheater section headers subject to accessibility. There has been no abnormality observed to date. Also, UT measurements were taken on the headers next to MPI locations. No significant header wall thinning was noted.

During the 2001 outage, the reheater inlet header and all ten vertical reheater headers were internally inspected. Handhole caps in the vertical headers were not removed. These headers were inspected through tube stubs with a boroscope prior to installing plugs.

During the 2003 outage, a boroscope inspection of the reheater outlet header was conducted and a layer of scale was noted on the inside surfaces. The scale was adhered and there did not appear to be any significant accumulation of loose scale in the header.

During the 2007 outage, the reheater outlet header was inspected using a boroscope. Evidence of exfoliating scale was found and it was noted that it could be the source of solid particle erosion that has been found in the turbine. There was no indication of any ligament cracking but a close-up view of the ligaments could not be taken due to the limitations of the boroscope.

**Asset 8360 Superheater Link Piping and Attemperator**

During the 2009 outage, a boroscopic internal visual inspection of the superheater attemperator was completed. Also, the spray assembly was removed for a better inspection of the liner. There were no obvious problems detected. However, it would have been difficult to identify fine defects with the limitations of the equipment. It was concluded the liner was 100% intact and appeared to be in good condition.

**Asset 8340 Economizer Tubes**

There were minor tube misalignment problems experienced in the past when the misalignment caused a sharp contact with tube support saddles. These were primarily due to the offset tubes that accommodate the circumferential seams in the economizer outlet header. Such problems were corrected during outages. Also, some of the spacer pins on the tubes were seen to overlap causing the tubes to be close together. However, there was no contact between the tubes.

During the 2008 outage, an angle beam UT inspection of the first 3 inches of twelve tubes at the economizer inlet header was carried out. The first two and last two rows were selected along with other tubes at random and no defects were found.

**Asset 8351 Waterwall Tubes**

During the 2007 outage, two tube samples were removed and a boroscope inspection of the remaining tubes above and below these tube samples was completed. The samples were removed from each side wall at a location approximately 1/3 of the boiler depth from the rear furnace wall. The tubes were found to be free of any heavy build-up or attack. However some corrosion was noted on butt joints. Also, a thermocouple was installed on each sidewall to measure the inside membrane temperature at the request of the regulator as a result of the Unit 2 waterwall experience.

Extensive pitting has been observed throughout the furnace, particularly on the front and side walls around the burner elevations. General wastage has been noted with some isolated deep pits. Also, corrosion of the furnace floor tubes has been observed. UT measurement readings are taken to monitor the corrosion.

**Assets 8360/8384 Superheater and Reheater Tubes**

The 2007 outage report documents slight pitting in the primary superheater section tube at the 8th floor above the sootblower. A random thickness measurement was taken on the lower secondary superheater section of Unit 3 during the 2003 outage and all tubes checked were found to be well above the design thickness. There was tube misalignment experienced due to burned back support saddles, failure of alignment lugs due to fretting, tube hanger detachment from the support lug along the front/baffle wall, and the tubes were not contacting on the support saddles. New saddles are installed as required and the loops are pulled up and set onto the new saddles depending upon the outage schedule. There was no evidence of sootblower erosion.

**Asset 8384 Reheater**

During the 2001 outage, a total of 44 square metres (460 square feet) was removed from the primary (lower) reheater section by removing and plugging one tube from each platen. The remaining tubes were replaced, with the lower two rows upgraded from SA-213-T22 to SA-213-TP 347H and the remaining tubes with SA-213-T22 material. Also, a total of 175 square metres (1858 square feet) of heating surface was removed from the secondary (upper) reheater by removing four passes from each of the 60 elements. New “dog-leg” sections were installed to join the original tube ends in the horizontal section to the original tube ends in the vertical section near the baffle wall. Sagging has been observed in the primary reheater tubes (these were new tubes installed in 2001). Some tubes have sagged and are nearly in contact with the tube below in most platens near the middle of the unit.

**Asset 8337 Safety Valves, Casings, & Structure/Hangers**

Safety relieve valves (SRVs) are inspected and maintained as per the plant SRV testing and overhaul program. The program and is considered adequate to maintain the SRVs for the desired life of 2020.

Casing: The casing has a history of failures associated with both fabric and metallic expansion joints. These are repaired and replaced as required. Failures of both fabric and metallic expansion joints are an ongoing issue. During the AMEC field walkdown, some boiler expansion joints were found leaking.

Steel Structure and Hangers: Corrosion in the boilers penthouse areas was identified in walkdowns of the unit. The condition of the boiler refractory is uncertain.

**Asset 8494/8495 Boiler Blow Down Tank**

The unit is inspected annually, except in 2009 and 2010. In 2009, the unit was inspected externally only due to access and isolation issues. Deterioration of internals and corrosion have been continuing issues, but safety concerns with access, isolation, and cramped spaces are primary concerns.

### 10.2.1.4 Condition Assessment

The condition assessment of the Unit boiler system is illustrated below in Table 10-27.

**TABLE 10-27 CONDITION ASSESSMENT – UNIT 3 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 55 | 30 | No active high energy piping management program. High temperature piping constant support hanger monitoring program discontinued after 2001. A few skewed hangers, topped or bottomed up constant spring support, and interference problem (only Unit 3) for main steam, hot reheat and cold reheat lines. | 4 | 200000 (30) | (5) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 56 | 30 | Four upper riser tubes inspected during 2004 outage and no defect found. no internal inspections of the lower waterwall headers for ligament cracking or cracking at other locations due to thermal/corrosion fatigue. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Headers & link Piping | 57 | 30 | Few problems with economizer outlet headers or link piping to the steam drum. 2008 outlet tubes inspection considered adequate. Results of internal inspection of inlet header in 2002 not known. No inspections of economizer recirculation line at connection points to economizer inlet and waterwall circuit. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Tubing | 58 | 30 | Insufficient inspections to assess damage. Wall thickness review inconclusive -some 2009 readings decreased and some increased vs 2004. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8339 | 8344 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 59 | 30 | No major life limiting issues observed during previous limited steam drum inspections. Design assessed as having no significant concerns. Inspections were focused at visible areas only and many of the susceptible locations have not been inspected. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | tubes | 62 | 30 | No significant life limiting issue has been observed in the primary superheater section tubes. No thickness measurement record available. Slight OD pitting noted on primary superheater tubes. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8362 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMPERATOR | N/A | 63 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. Internal inspection of superheater attemperator in 2009 found no thermal fatigue damage. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Headers & link Piping | 64 | 30 | Design creep life calculations for secondary superheater outlet headers suggest concern. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Tubes | 65 | 30 | No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8379 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 68 | 30 | Design calculations for combination creep and fatigue damage from thermal fatigue raises concern with attemperators. Internal inspection of superheater attemperator in 2009 found no thermal fatigue damage. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Pipes | 69 | 30 | No NDE or metallographic examination reports were found. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Headers & link Piping | 70 | 30 | Design creep life calculations for reheater outlet headers suggest concern. Internal scale noted in reheater outlet header during previous outage inspections. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Tubing | 71 | 30 | No inspections, including destructive tube sample analysis, done assessing the extent of damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | Piping | 72 | 30 | No NDE or metallographic examination reports were found. | 4 | 200000 (30) | (10) | 2020 | | 2012 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 73 | 30 | Original Equipment. No details available. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2012 | Yes | No | 1980 |
| 1296 | 8193 | 8336 | 8339 | 8339 | 0 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | N/A | 74 | 30 | Thinning, corrosion. Sefety issues - isolation and access. | 10 | 200000 (30) | (3) | 2020 | 2013 | 2013 | Yes | No | 1980 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.1.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 boiler system.

**TABLE 10-28 RECOMMENDED ACTIONS – UNIT 3 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 88 | | See details below. | | |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 89 | 30 | Perform Level 2 inspections to assess corrosion fatigue, general wall loss and pitting. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 90 | 30 | Review the destructive testing 2007 report of waterwall tubes to evaluate the findings. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 91 | 30 | Inspect selective flat end welds of the upper waterwall headers. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 92 | 30 | Inspect the selective feeder and riser tubes for corrosion fatigue damage. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 93 | 30 | Perform preliminary internal inspection of lower waterwall headers of the locations and degradation mechanisms identified for steam drum, using boroscope; inspection of selective flat end welds, feeder tube attachment welds and downcomers connection welds. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 94 | 30 | Perform preliminary inspection of superheater and reheater headers support locations on the downcomers for thermal/mechanical fatigue. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 95 | 30 | Perform inspection including sample tube removal and ultrasonic sonic testing survey at the accessible locations to assess the potential corrosion fatigue damage | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 96 | 30 | Modify start-up procedures to include monitoring of the thermocouple temperature and using the continuous feed during start-ups. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 97 | 30 | Perform Level 2 inspections for the economizer inlet header.<br>i. ID visual inspection of bore holes, girth welds and tee welds. If cracking is identified, depth must be assessed. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 98 | 30 | Visually inspect the economizer outlet headers and supports and the economizer link piping during annual outages to ensure there is no change in the state and/or abnormal movement. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8340 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 99 | 30 | Inspect economizer recirculation line welds to economizer inlet and waterwall circuit. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8344 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 100 | 30 | Remove the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8344 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 101 | 30 | Perform external inspection of feeder tube welds. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8344 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 102 | 30 | Manage steam drum target life with appropriate operational control and routine inspection and maintenance. | 2010 | 1 |
| 1296 | 8193 | 8336 | 8359 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | N/A | 104 | 30 | Inspect superheater and reheater outlet headers and superheater attemperator header for creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8360 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 105 | 30 | Inspect to check the presence of inside pitting and scaling. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8360 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 106 | 30 | Inspect to assess OD pitting and corrosion. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8360 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 107 | 30 | Enhance the present inspection and maintenance program to monitor and control the tubes alignment issues including failure of saddle supports and alignment lugs. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8362 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP | N/A | 108 | 30 | No action recommended. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8366 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 109 | 30 | Perform destructive tube sample analysis on the secondary superheater section to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8366 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 110 | 30 | Enhance the present inspection and maintenance program to monitor and control failures of saddle supports and alignment lugs issues. | 2011 | 2 |

Table 10-28 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8359 | 8379 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 111 | 30 | Inspect attemperator and ID of the link piping for evidence of thermal fatigue. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 112 | 30 | Check the presence of inside pitting and scaling. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 113 | 30 | Inspect to assess OD pitting and corrosion. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 114 | 30 | Perform destructive tube sample analysis to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion, ID high temperature corrosion and DMWs. | 2014 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 115 | 30 | Enhance the present inspection and maintenance program to monitor and control failures of saddle supports and alignment lugs issues. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8384 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 116 | 30 | Refurbish and use the furnace exit thermoprobe during start-up activities. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | N/A | 117 | 30 | Implement an active high energy piping management program including NDE testing at key locations and an high temperature piping constant support hanger monitoring program. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 117a | 30 | Not assessed in detail. Inspect and refurbish/replace during next major boiler outage. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8339 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | N/A | 118 | 30 | Replace tank. | 2013 | 1 |

### 10.2.1.6 Risk Assessment

The risk assessment associated with the Unit 3 boiler system, both from a technological perspective and a safety perspective, is illustrated below in Table 10-29.

**TABLE 10-29 RISK ASSESSMENT – UNIT 3 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | | 70 | 30 | See detail below. | | | | | | | | | | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Upper WW Headers | 71 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking in flat end welds, corrosion. | 10 | Could meet the desired life with routine inspections. | 2 | B | Low | 2 | C | Medium | Flat end weld cracking. Wall thinning due to corrosion. | Routine inspections. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Riser Tubes | 72 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 1 | B | Low | 2 | C | Medium | Wall thinning due to corrosion. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Lower WW Headers | 73 | 30 | Thermal fatigue cracking, corrosion-fatigue cracking, corrosion. | (10) | No real life limiting issue. Additional inspections. | 3 | B | Med | 3 | B | Medium | Ligament cracking and weld cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Feeder Tubes | 74 | 30 | Corrosion, corrosion fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Corrosion fatigue cracking and wall thinning due to corrosion related mechanism. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Downcomers | 75 | 30 | Thermal/mechanical fatigue. | 10 | No real life limiting issue. | 1 | B | Low | 3 | B | Medium | Thermal/mechanical fatigue. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Primary Sat. Steam Header | 76 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | C | High | Thermal fatigue cracking. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Waterwall Tubes | 77 | 30 | Corrosion fatigue, thermal/mechanical fatigue, water side under-deposit corrosion, short-term overheat, fireside corrosion/erosion. | (10) | Some sections of floor tubes require attention, other than that no major life limiting issue observed. Additional inspections required. | 3 | B | Med | 3 | B | Medium | Tube failure due to corrosion fatigue, general wall loss and pitting at the susceptible locations. | Pitting in some areas require attention. |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Inlet Headers | 78 | 30 | Thermal/mechanical fatigue cracking, corrosion-fatigue cracking, corrosion, FAC. | (10) | No real issue as per inspection to date. Additional inspections required | 3 | B | Med | 3 | B | Medium | Ligament cracking, tube stub thinning/cracking, weld cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 79 | 30 | Mechanical fatigue cracking, corrosion-fatigue cracking, corrosion. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | B | Low | Weld cracking due to support failure. | Routine inspections. |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Recirculation Line | 80 | 30 | Thermal fatigue. | (10) | Inspections are required to assess the remaining life. | 3 | B | Med | 3 | B | Medium | Weld cracking. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Tubes | 81 | 30 | External corrosion and corrosion-fatigue. | (10) | Inspections are required to assess the remaining life. | 1 | B | Low | 1 | B | Low | Tube failure due to corrosion, corrosion-fatigue. | Inspections are required to assess remaining life. |
| 1296 | 8193 | 8336 | 8339 | 8344 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | Steam Drum | 82 | 30 | Thermal/mechanical fatigue. | 10 | No real life limiting issue. | 3 | C | Med | 3 | C | High | Thermal/mechanical fatigue. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Inlet Header | 85 | 30 | Thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | High | Thermal fatigue cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Outlet Header | 86 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | High | Creep and thermal fatigue cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 87 | 30 | Fatigue, OD/ID corrosion, ID pitting. | 10 | No real life limiting issues; however, the presence inside pitting and scaling is not known. | 1 | C | Low | 1 | C | High | Tube failure due to excessive pitting and corrosion. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8362 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP | Superheater Attemperator Header | 88 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | C | Med | 3 | D | High | Creep and thermal fatigue cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Inlet Header | 89 | 30 | Creep and thermal fatigue. | 10 | No real life limiting issue. Could meet the desired life with routine inspections. | 1 | C | Low | 1 | D | High | Creep and thermal fatigue cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Outlet Header | 90 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Tubes | 91 | 30 | Creep, OD/ID corrosion, ID pitting and sagging. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | C | High | Tube failure due to creep and Creep, OD/ID corrosion, ID pitting. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8379 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 94 | 33 | Not addressed in detail | (10) | Additional inspections required to assess the remaining life. | 3 | B | Medium | 3 | C | High | Creep and thermal fatigue cracking. | Inspection and refurbish or replace. |

Table 10-29 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Hot Reheat | 95 | 33 | Thermal/mechanical fatigue, creep, creep-fatigue, corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (> 25% for Unit 3 at end 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for U1 & 2 (1987 to 2002); no significant crack or damage found. No major damage found during walkdowns. | 3 | C | Med | 3 | D | High | Pipe and/or weld failures at potentially high stress locations. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. FOCUS Phased Array and Metallographic Inspections at key locations Hanger/Support Inspection and Monitoring Program. Level 2 assessments. |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Cold Reheat | 96 | 33 | Thermal/mechanical fatigue, corrosion-fatigue, cracking, corrosion. | (10) | No seam-welded pipe. No NDE inspection or material testing done in recent past. Not possible to assess current condition or remaining life. No major damage found during walkdowns. | 1 | B | Low | 1 | D | Low | Pipe and/or weld failures at potentially high stress locations. | Piping Management Program. Hanger/Support Inspection and Monitoring Program. Level 2 assessments. |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Inlet Header | 97 | 30 | Thermal fatigue. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Low | Thermal fatigue cracking. | Inspect and maintain. |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Lower and upper Reheater Link Header | 98 | 30 | Thermal fatigue. | 10 | Could meet the desired life with routine inspections. | 1 | B | Low | 1 | D | Low | Thermal fatigue cracking. | Inspect and maintain. |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Outlet Header | 99 | 30 | Creep and thermal fatigue. | (10) | Additional inspections required to assess the remaining life. | 3 | D | High | 3 | D | High | Creep and thermal fatigue cracking. | Inspect and maintain. |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Tubes | 100 | 30 | Creep, OD/ID corrosion, ID pitting, stress corrosion cracking and DMWs. | (10) | Inspections are required to assess the remaining life. | 3 | C | Med | 3 | C | High | Creep, fatigue and stress corrosion cracking damage, wall thinning due to corrosion and pitting and DMW failures. | Additional inspections required. |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | N/A | 101 | 33 | Thermal/mechanical fatigue, creep, creep-fatigue, corrosion. | (10) | Major issue is creep and creep fatigue. Creep life fraction expended is high (> 25% for Unit 3 at end 2009). No evidence of upset or thermal fatigue. Metallographic inspections conducted in past for U1 & 2 (1987 to 2002); no significant crack or damage found. No major damage found during walkdowns. | 3 | D | High | 3 | D | High | Pipe and/or weld failures at potentially high stress locations. | Inspect hot and cold walkdowns to assess hanger condition and potential high stress locations. Conduct inspections of welds at potentially high stress locations. |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 101a | 33 | Not addressed in detail. Thermal/mechanical fatigue. creep, creep-fatigue, corrosion. | (5) | Additional inspections required to assess the remaining life. | 3 | C | Medium | 3 | C | High | Creep and thermal fatigue cracking. | Inspection and refurbish or replace. |
| 1296 | 8193 | 8336 | 8339 | 8339 | 0 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | N/A | 102 | 33 | Not addressed in detail. Thermal/mechanical fatigue. creep, erosion. | (2) | Safety issue. End of life. | 2 | B | Medium | 3 | C | High | Mechanical failure. Steam leak. Personal injury. | Replace |

### 10.2.1.7 Life Cycle Curve and Remaining Life

The life cycle curves for the various elements of the Unit 3 boiler system is broken into three separate parts – the boiler headers and components outside the flue gas path, the high pressure and temperature steam lines (main steam, reheat steam), and the tubes exposed to the combustion process and/or flue gas within the boiler. Differences between the scenarios do not materially affect the curve.

The boiler headers and components are subject primarily to time spent under the effects of steam pressure and temperature. Their equivalent expended life presented in figure below is primarily related to the material properties and the steam conditions. As a result several curves are required to represent the range of the various elements of the system. Details are included in Appendix 30. The life curves are plots on the y-axis of current and projected consumed equivalent life hours based on the theoretical metallurgical assessments. This differs from other sections that use nominal operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the “Level 2 Test” box identifies where EPRI recommends an initial Level 2 analyses or equivalent for these sorts of components (consumed life = 10% of expected or design life).

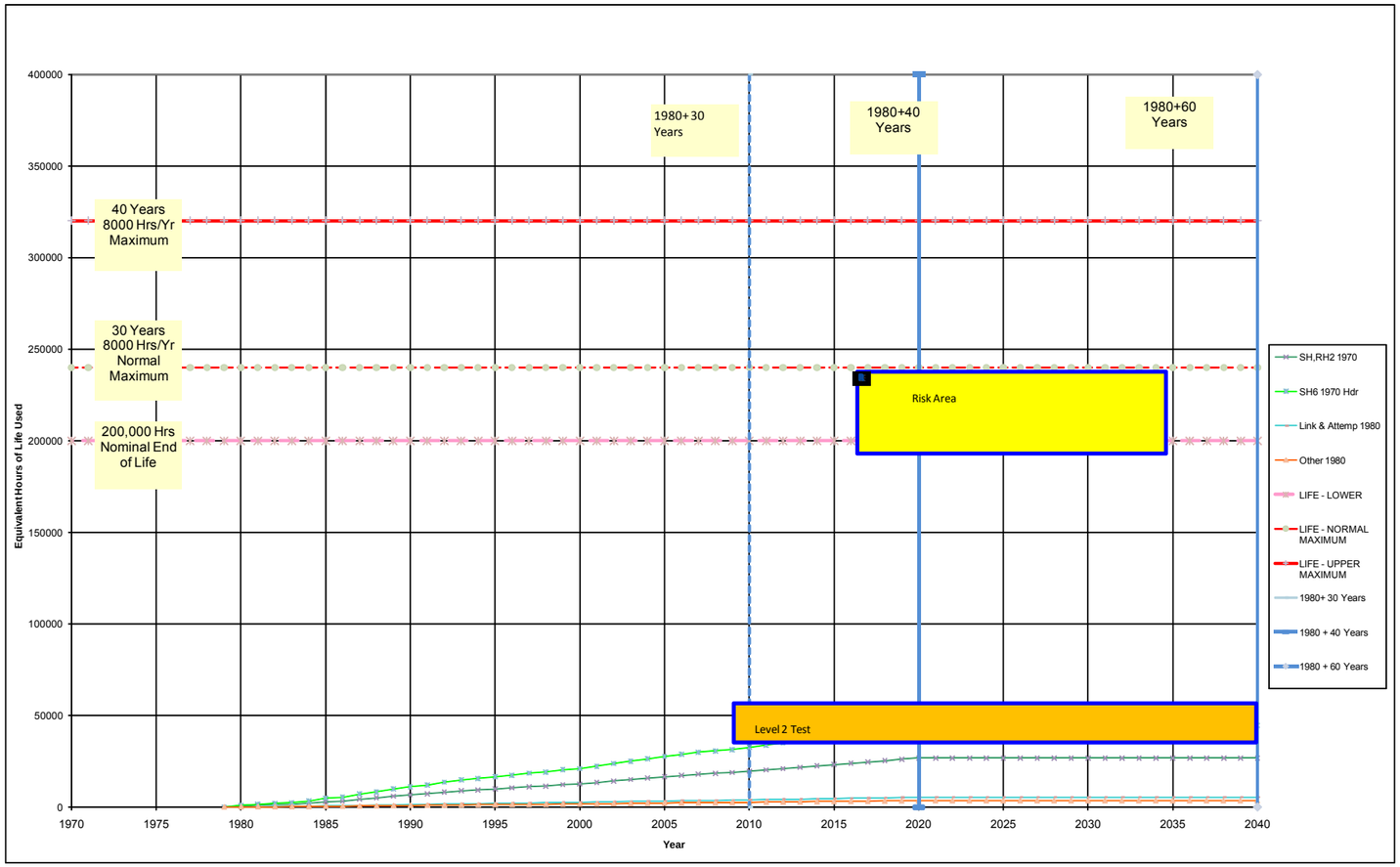



**FIGURE 10-13 LIFE CYCLE CURVE – UNIT 3 BOILERS (HEADERS AND COMPONENTS)**

The header life curves indicate that the remaining life (RL) of the Unit 3 boiler headers and associated components is expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless, it also identifies that some of higher temperature components should undergo a Level 2 inspection (identified later in this section of the report) if not already planned or undertaken.

Three curves represent the high pressure, high temperature steam lines (main steam, hot reheat, and cold reheat). Their life expenditure (illustrated in figure below) is primarily related to the time spent under the effects of steam pressure and temperature (similar to the boiler headers) and to the material properties of the steam lines. Details are included in Appendix 33. The life curves are plots on the y-axis of current and projected "consumed equivalent life hours" based on the theoretical metallurgical assessments. The figure has three vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The figure also included two highlighted boxes. The risk box is representative of typical life expectations. The second identified as the "Level 2 Test" box identifies where an initial Level 2 analyses or equivalent is likely required (consumed life = 10% of expected life).

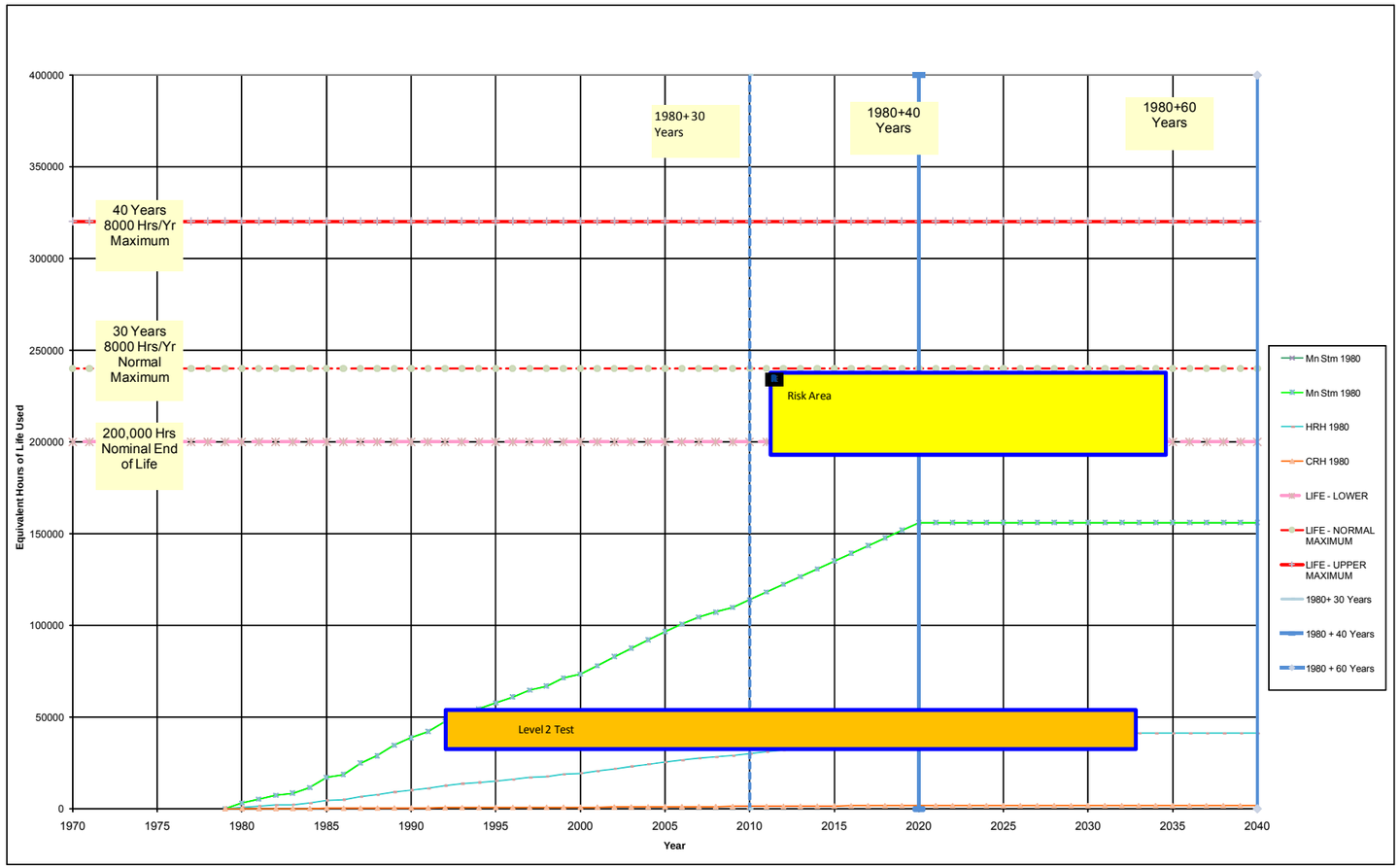



**FIGURE 10-14 LIFE CYCLE CURVE – UNIT 3 BOILERS (HIGH PRESSURE AND TEMPERATURE STEAM LINES)**

The high pressure steam line life curves indicate that the remaining life (RL) of the Unit 3 steam lines and their associated components are expected to exceed the desired life (DL) which is the generation end of life in 2020. Nevertheless it also identifies that both the main steam and hot reheat steam lines exceed EPRI's 10% consumed life guide for a Level 2 inspection of these systems. Given that they have not been tested for some time, this is considered appropriate at this time.

The Unit 3 boiler system tubes and associated components (exposed to combustion process and/or flue gas within the boiler) are subject to both internal water and/or steam intermediate temperatures and high pressures, but also externally to higher combustion temperatures, and corrosive and erosive conditions. Typically, the externally conditions often are the life limiting factor. This is certainly the case for Holyrood units which were fuelled with a high sulphur, high vanadium, moderate ash heavy oil up until 2009. This is evident in the reliability statistics for the boilers, the multiple boiler outages for air preheater cleaning, economizer fouling history, and in the fairly extensive tube surface changes to 2009. The move to a lower sulphur, lower vanadium oil has effectively minimized these going forward, but some legacy effects are inevitable.

A single life cycle curve is presented beginning with the in-service date of the unit. It is meant to represent initial design goals, using nominally operating hours. It was considered impractical to accurately document or reasonably present in one curve the many changes that have occurred, and are likely to continue to occur going forward due to legacy impacts. It is shows the current status of the boiler blowdown tank, which is both a life issue and a safety issue. It uses nominal operating hours as opposed to metallurgical equivalent hours in the two previous boiler curves as a more appropriate way of expressing its normal lifetime.

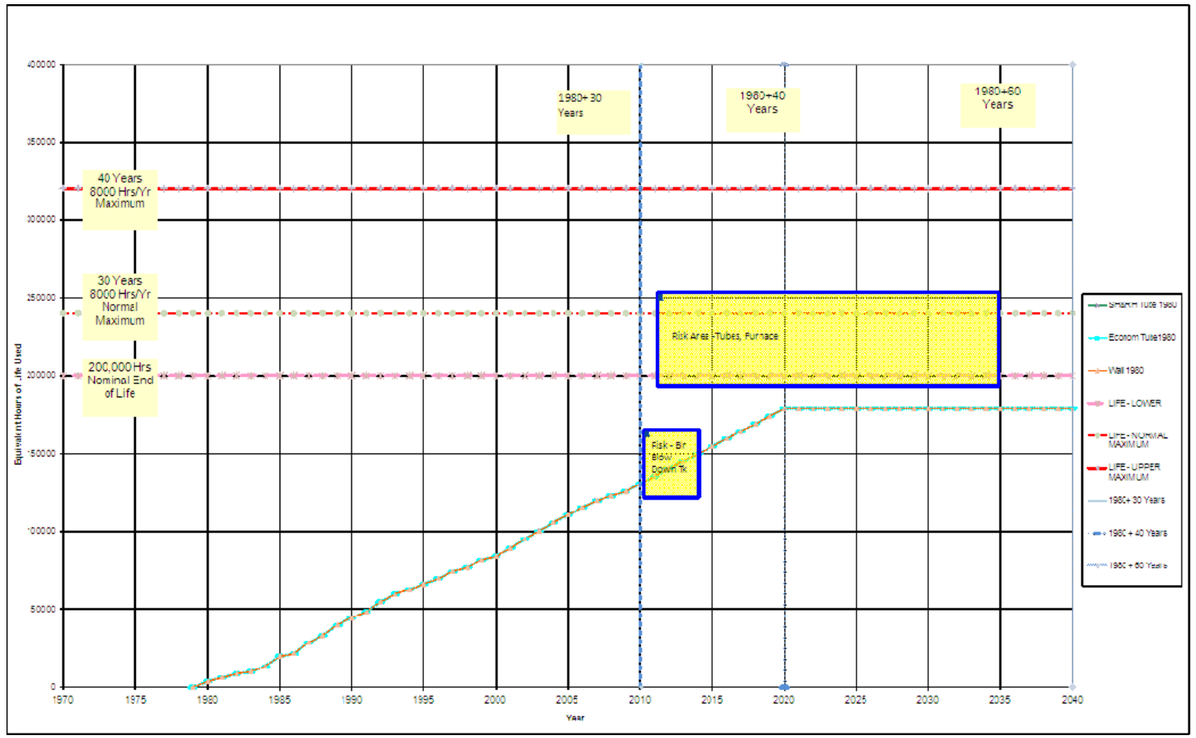



**FIGURE 10-15 LIFE CYCLE CURVE – UNIT 3 BOILER SYSTEM (TUBES EXPOSED TO THE COMBUSTION PROCESS)**

The curve indicates that the boiler tubes within the furnace envelope would have been expected to be seeing some end of life component concerns with original equipment. Nevertheless, it is more likely legacy impacts that will have greater effects on component replacements and refurbishments going forward to 2020. With ongoing inspections and refurbishments, 2020 is achievable with good reliability with the new fuel. It also shows that the boiler blowdown tank should be replaced.

### 10.2.1.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-30 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-30 LEVEL 2 INSPECTION – UNIT 3 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | None | 54 | 30 | Level 2 - Covers all boiler pressure part system costs - economizer, reheat, superheat, drum. | 2014 | 1 | $1,520 |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Upper WW Headers | 55 | 30 | Inspection of selective flat end welds. External visual and thickness measurement. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Riser Tubes | 56 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Lower WW Headers | 57 | 30 | Inspections of ligament cracking, selective flat end welds, body spool pieces welds, feeder tube attachment welds and downcomers connection welds. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Feeder Tubes | 58 | 30 | Inspection of selective riser tube for corrosion fatigue cracking. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Downcomers | 59 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | Waterwall Tubes | 60 | 30 | Inspections to assess corrosion fatigue, general wall loss and pitting at the susceptible locations. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Inlet Headers | 61 | 30 | Inspection of internal surfaces, ligaments, major girth and seam welds and drain line penetrations. UT inspection of stub tubes and a stub tube sample removal to assess evidence of FAC. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Outlet Headers and Link Piping | 62 | 30 | External visual inspection to ensure that there is no change in the state and/or abnormal movement. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Recirculation Line | 63 | 30 | Inspect economizer recirculation line welds to economizer inlet and waterwall circuit. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | Economizer Tubes | 64 | 30 | Sample tubes removal. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8339 | 8344 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | Steam Drum | 65 | 30 | Removal of the drum furniture and a section of the liner to inspect seam welds, nozzle welds, ligaments, downcomers and feedwater inlet pipe. External inspection of feeder tube welds. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Sat. Steam Header | 68 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Inlet Header | 69 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Outlet Header | 70 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |

Table 10-30 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | Primary Superheater Tubes | 71 | 30 | Inspections to check the presence inside pitting and scaling. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8362 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP | Superheater Attemperator Header | 72 | 30 | Creep and creep fatigue damage including internal boroscopic, external visual, dimensional on body spool pieces, UT inspections on welds and stub tubes and replica inspection. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Inlet Header | 73 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Outlet Header | 74 | 30 | Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection. | 2014 | 1 | |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | Secondary Superheater Tubes | 75 | 30 | Inspections to assess the extent of the damage due to creep, sagging, OD liquid ash corrosion and ID high temperature corrosion for creep, fatigue corrosion and pitting. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8359 | 8379 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | None | 76 | 30 | No Level 2 inspections or testing is required. | 2014 | | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Inlet Header | 77 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Lower and Upper Reheater Link Header | 78 | 30 | No Level 2 inspections or testing is required. | 2014 | 3 | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Outlet Header | 79 | 30 | Internal boroscopic, external visual, dimensional on body spool pieces for creep and creep fatigue damage; UT inspections on welds and stub tubes and replica inspection. | 2014 | 1 | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Reheater Tubes | 80 | 30 | Inspections to assess the extent of the damage due to destructive tube sample analysis to assess the extent of the damage due to creep, OD liquid ash corrosion, ID high temperature corrosion, stress corrosion cracking and DMWs. | 2014 | 2 | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 99000154 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | HIGH PRESSURE STEAM SYSTEM | None | 81 | 30 | No Level 2 inspections or testing is required. | 2014 | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 99000155 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | HIGH PRESSURE STEAM SYSTEM UNI | None | 82 | 30 | No Level 2 inspections or testing is required. | 2014 | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater | 83 | 30 | Level 2 testing of steam and high pressure feedwater lines. | 2012 | 1 | $407 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | None | 83a | 30 | Level 2 testing of boiler stop valves as part of main steam lines program. | 2012 | 1 | $31 |
| 1296 | 8193 | 8336 | 8339 | 8339 | 0 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | None | 84 | 30 | No Level 2 inspections or testing is required. | | | |

### 10.2.1.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 boiler system include:

**TABLE 10-31 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 BOILER SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | N/A | 56 | 30 | 3 | Install nitrogen blanketing. No other pending Level 2 or next inspection. | 2013 | 2 |
| 1296 | 8193 | 8336 | 8339 | 0 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | N/A | 57 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8339 | 8340 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER ECONOMIZER | N/A | 58 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8339 | 8344 | 0 | 3 | BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER STEAM DRUM | N/A | 59 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 0 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER & REHEAT | N/A | 61 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8360 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER PRIMARY SUPERHEATER | N/A | 62 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8362 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SUPERHEATER ATTEMP | N/A | 63 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8366 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER SECONDARY SUPERHEATER | N/A | 64 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 99000154 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | HIGH PRESSURE STEAM SYSTEM | N/A | 65 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 99000155 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | HIGH PRESSURE STEAM SYSTEM UNI | N/A | 66 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8379 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER ATTEMPERATOR | N/A | 67 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8384 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | N/A | 68 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | N/A | 69 | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | N/A | 69a | 30 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8336 | 8339 | 8339 | 0 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | N/A | 70 | 30 | 3 | Replace blowdown tank. | 2011 | 1 |

### 10.2.2 Asset 8611 – Unit 3 Feedwater System - HP Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendices 32 and 34)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8523 #3 Condensate & Feedwater System |
| Sub-Systems: | 8611 #3 High Pressure Feedwater |
| Components: | 8818 #3 H.P. Heater 4 |
| | 8819 #3 H.P. Heater 5 |
| | 8820 #3 H.P. Heater 6 |
| | 8848 #3 Boiler Feed Pump East |
| | 8847 #3 Boiler Feed Pump West |

#### 10.2.2.1 Description

High pressure (HP) feedwater systems servicing Unit 3 contain three HP feedwater heat exchangers that are referred to as HP-4, HP-5 and HP-6. The primary function of the HP feedwater heat exchangers is to optimize the unit thermal efficiency by preheating the feedwater prior to entering the boilers.

Each HP feedwater heat exchanger is a horizontally mounted, 100% capacity pressure vessel of the U-tube type construction. There are two tube passes on the feedwater side and divided flow of steam on the shell side of the HP feedwater heater. The main components of the HP feedwater heaters are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. Tubesheet and channel are made from a single forging. The tubes material for all three HP feedwater heaters is stainless steel SA-688.

There are three zones on the shell side that are commonly referred to as desuperheating, condensing, and drains subcooling.

1. Desuperheating Zone: This is an enclosed portion at the outlet end of the tube bundle. An impingement plate is installed below the steam inlet nozzle to prevent impingement damage to the tubes. The desuperheating zone is enveloped by a separate shroud which conducts the steam from the inlet nozzle to the condensing zone.

2. Condensing Zone: Steam exiting the desuperheating zone is condensed as it traverses through the condensing zone. Also, any drains from higher pressure heater flow into the condensing zone through the drains inlet nozzle. An impingement plate is installed just inside this nozzle to protect the tubes from these flashing drains. The condensing zone is vented continuously to remove non-condensable gases.

3. Drains Subcooling Zone: This zone is an enclosed portion of the inlet end of the tube bundle to maximize heat transfer from the shell side condensate to the incoming feedwater before the condensate exits. The condensate should be sub-cooled sufficiently to prevent flashing as the condensate leaves the HP feedwater heater shell through the drains outlet nozzle.

Two motor driven boiler feed pumps (BFP) service Unit 3. The pumps are multiple stage, barrel centrifugal pumps. Each can provide up to 60% of full load requirement. They have been in service since 1980. The pump motors are 4 kV with a power rating of approximately 1750 kW. They directly drive the pumps. There is no variable speed devices such as variable frequency drives or fluid couplings.

#### 10.2.2.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.2.3 Inspection and Repair History

There have been no NDE inspections carried out on the HP feedwater heat exchangers currently in service, with the exception of tube leak testing and yearly PM checks. A long term commitment (life-cycle management plan) is required to track and diagnose failures and identify possible remedial actions in order to mitigate similar future occurrences.

HP-4, HP-5 and HP-6 were installed in December 1997 and hence have accumulated less operating hours than other plant HP feedwater heat exchangers, with the exception of Unit 2 HP-5 that was installed in 2009. However, their operating life is greater than the EPRI recommended interval of 5 years for NDE inspections.

The Unit 3 boiler feed pumps and motors are regularly maintained. The plant has a common spare pump barrel that they use to be able to refurbish all of the plant pumps on a six to seven year cycle. The 4 kV motors are tested electrically annually. No specific issues have been identified, but the BFP motors are at a stage in life where failures may be anticipated.

### 10.2.2.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system – HP feedwater heat exchangers is illustrated below in Table 10-32.

**TABLE 10-32 CONDITION ASSESSMENT – UNIT 3 FEED WATER SYSTEM HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8590 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | Motors | 125 | 23 | 4160V Motor annual tests. On-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pumps, using a spare barrel, are refurbished about every seven years. | 3a | 150000 (25) | (5+) | 2020 | | 2014 | Yes | No | 1980 |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 126 | 23 | Pumps installed in 1978 and motors in 1979. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2008, planned for 2014. | 3a | 200000 (30) | 10+ | 2020 | 2014 | 2014 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 127 | 23 | Pumps installed in 1978 and motors in 1979. Good condition due to pump refurbishment using spare barrel. Last pump refurbishment 2005, planned for 2013. | 3a | 200000 (30) | 10+ | 2020 | 2013 | 2013 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 128 | 32,33 | No Flow Accelerated Corrosion (FAC) management program. Present water chemistry and operating conditions indicates that the feedwater system is susceptible to FAC. | 4 | 150000 (20) | (5) | 2020 | 2012 | 2014 | Yes | No | 1980 |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 129 | 32 | Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2012 | 2014 | Yes | Yes | 2007 |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 130 | 32 | Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (20) | (10) | 2020 | 2012 | 2014 | Yes | Yes | 2007 |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 131 | 32 | Installed Dec 1997. HP feedwater tube leaks experienced plugged in order to satisfy the short-term problem with cause uncertain. Numbers of leaks and locations not known. Uncertain if SCC tube failure degradation mechanism observed at Unit 2 HP-5 applicable to other HP feedwater heaters. | 4 | (25) | (10) | 2020 | 2012 | 2014 | Yes | Yes | 2007 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.2.5 Actions

Based on the condition assessment, the following actions are recommended for Unit 3 feed water system – HP feedwater heat exchangers:

**TABLE 10-33 RECOMMENDED ACTIONS – UNIT 3 FEED WATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8590 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 184 | 23 | Assess potential for variable speed control of BFW pumps. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 185 | 23 | Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8659 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 186 | 23 | Maintain current program of ongoing inspections and overhauls. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8660 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 187 | 23 | Maintain current program of ongoing inspections and overhauls. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 188 | 23 | Assess potential for variable speed control of BFW pumps. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 189 | 23 | Assess potential for spare BFP motor, and subsequent refurbishment/rewind of Unit 3 motors. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8659 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 190 | 23 | Maintain current program of ongoing inspections and overhauls. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8660 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 191 | 23 | Maintain current program of ongoing inspections and overhauls | 2011 | 2 |
| 1296 | 8193 | 8528 | 8611 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 192 | 32 | See detail below. | | |
| 1296 | 8193 | 8528 | 8611 | 8618 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 193 | 32 | Develop a program of ongoing inspections and performance testing. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8611 | 8618 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 194 | 32 | Perform Level 2 inspections. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8611 | 8619 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 195 | 32 | Develop a program of ongoing inspections and performance testing. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8611 | 8619 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 196 | 32 | Perform Level 2 inspections. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8611 | 8620 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 197 | 32 | Develop a program of ongoing inspections and performance testing. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8611 | 8620 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 198 | 32 | Perform Level 2 inspections. | 2014 | 2 |

### 10.2.2.6 Risk Assessment

Table 10-34 below illustrates the risk assessment for the Unit 3 feedwater system – HP feedwater heat exchangers, both from a technological perspective and a safety perspective using the models presented in Section 3.

**TABLE 10-34 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8528 | 8590 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | Feedwater Discharge | 159 | 33 | Flow accelerated corrosion (FAC), thermal/mechanical fatigue cracking, corrosion-fatigue cracking, corrosion. | (10) | None | 3 | D | High | 3 | D | High | Conduct sample FAC inspections using EPRI methodology. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | FW Pump East | 160 | 23 | Seal, bearing, impeller failure. | 10 | None | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction. | Current inspection and maintain. |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | 4 kV Boiler Feed Pump Motor | 161 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | C | Medium | 2 | B | Low | Loss 60% unit generation for extended time. | Spare and current inspection and maintain. |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | FW Pump West | 162 | 23 | Seal, bearing, impeller failure. | 10 | None | 1 | C | Low | 1 | C | Low | Pump failure; 50% capability reduction | Current inspection and maintain. |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | 4 kV Boiler Feed Pump Motor | 163 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | C | Medium | 2 | B | Low | Loss 60% unit generation for extended time. | Spare and Current Inspection and Maintain |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 164 | 32 | SCC, thermal/mechanical fatigue. | (10) | Life management program is required. | 1 | C | Low | 1 | B | Low | Excessive tube failure event resulting in turbine water induction. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 165 | 32 | SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue. | (10) | Could meet the desired life; however, baseline | 2 | B | Low | 2 | B | Medium | Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 166 | 32 | SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue. | (10) | Could meet the desired life; however, baseline | 2 | B | Low | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 167 | 32 | SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue. | (10) | Could meet the desired life; however, baseline | 2 | B | Low | 2 | B | Low | Tube failures, internal hardware failure and shell wall thinning due to FAC and weld cracking. | Inspect and maintain. |

### 10.2.2.7 Life Cycle Curve and Remaining Life

The life cycle curves for the Unit 3 feed water system HP heat exchangers and Unit 3 boiler feed pumps are illustrated below. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

For the HP heat exchangers, curves represent the three heat exchangers and components, as well as a curve to represent any balance of plant that is original equipment.

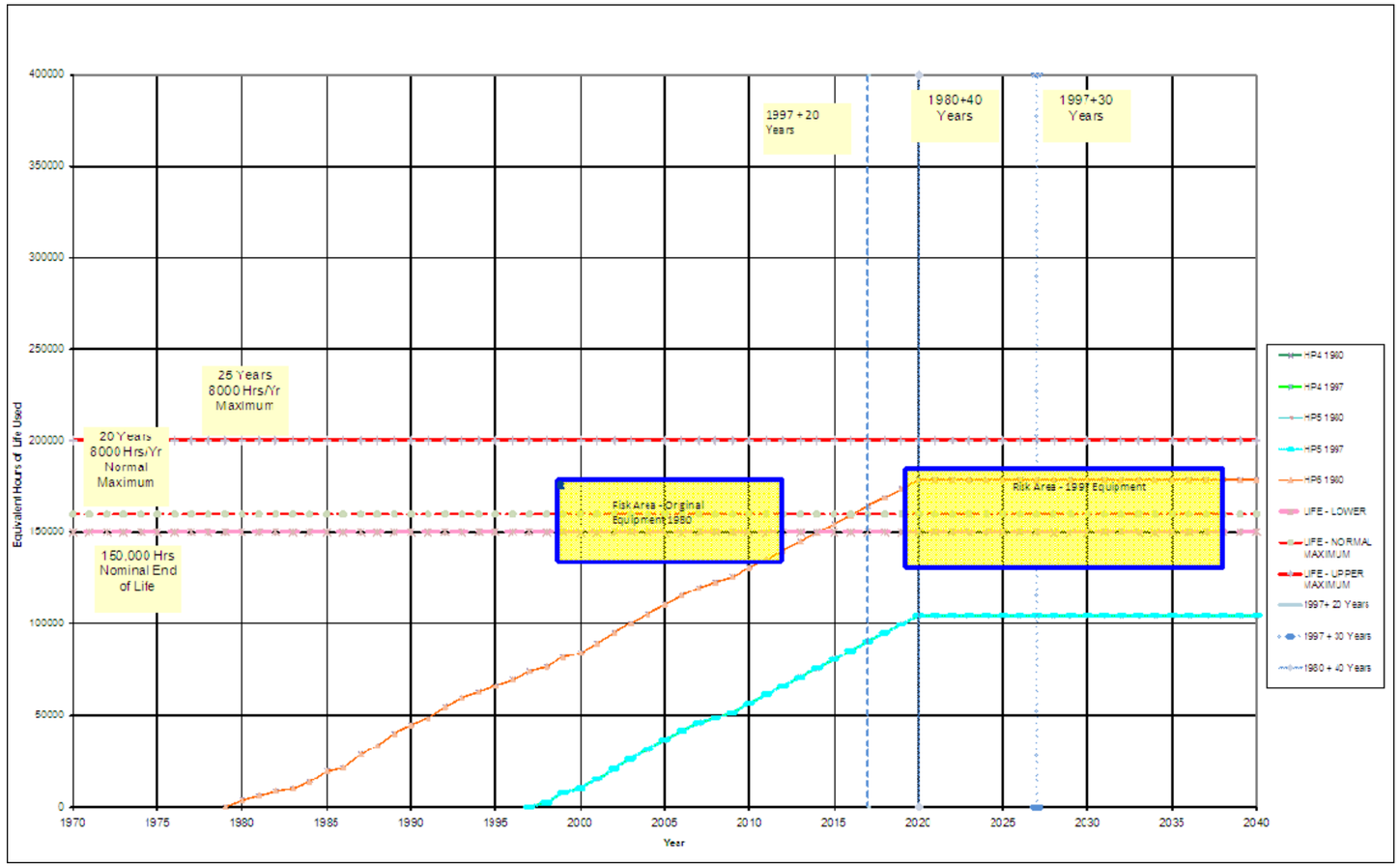



**FIGURE 10-16 LIFE CYCLE CURVE – UNIT 3 FEED WATER SYSTEM HP HEAT EXCHANGERS**

The curves indicate that the remaining life (RL) of the Unit 3 HP heat exchangers (and the associated feedwater systems) may be able to reach the desired life (DL) 2020 end date for generation. Nevertheless, given that no detailed NDE information has been obtained on the HP heat exchangers for some time, a detailed Level 2 inspection is recommended for 2014.

For the Unit 3 boiler feed pumps, a single curve represents each of the two boiler feed pumps dating back to their original installation. While indicative of expected life with good maintenance practice, the pumps have been and continue to be refurbished on a six year cycle using a spare pump section. Their actual condition is therefore substantially better than might otherwise be expected.

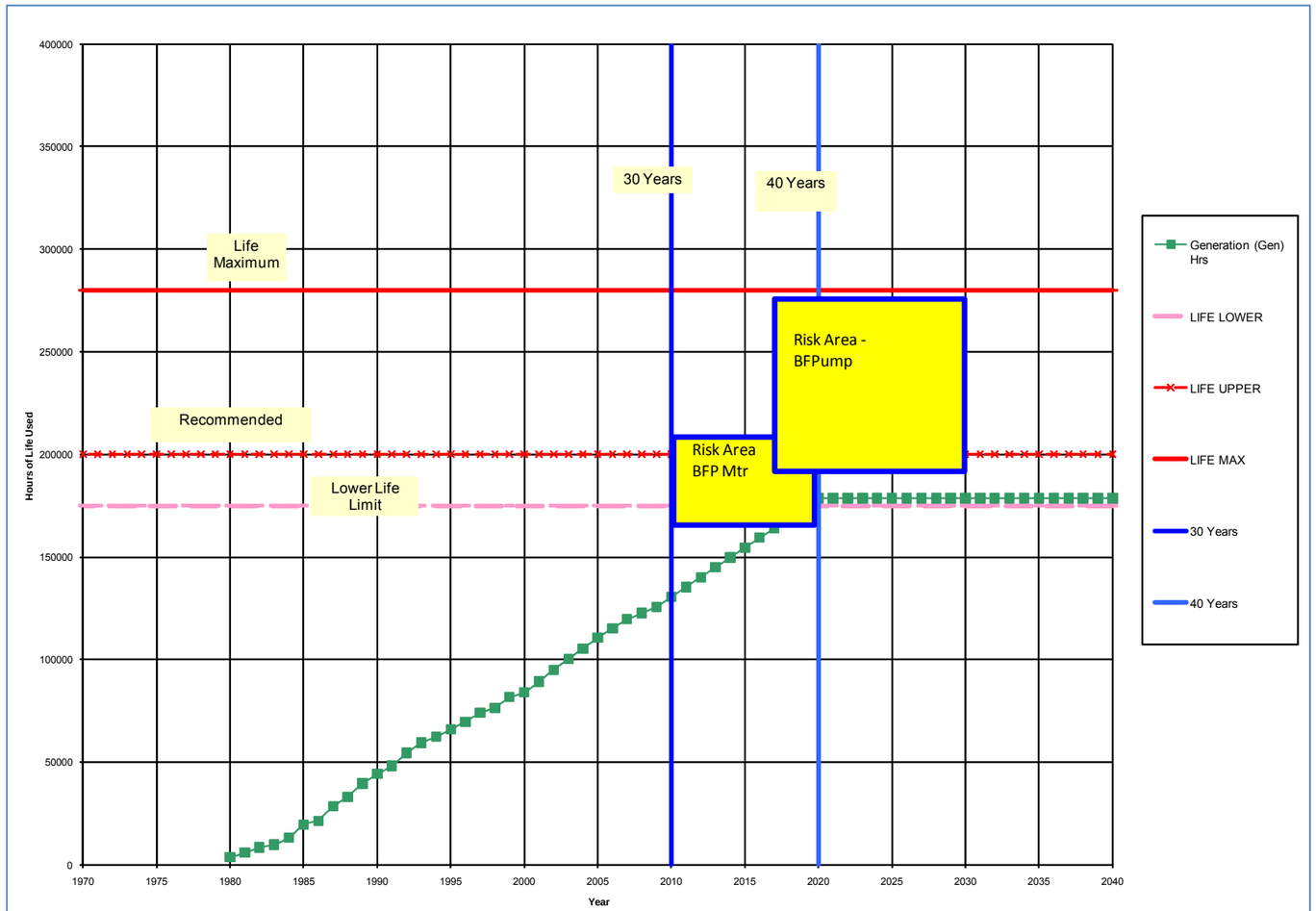



**FIGURE 10-17 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - BOILER FEED PUMPS**

The curve indicates that the remaining life (RL) of the Unit 3 HP boiler feed pumps is likely able to reach desired end date which is the 2020 end date for generation. Given their six year refurbishment cycle and a spare pump section, they are expected to continue to perform reliably well past the 2020 end date for generation. The BFP motors are approaching older age and entering areas where reliability and unexpected failure may become more an issue than expected life.

### 10.2.2.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-35 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-35 LEVEL 2 INSPECTION – UNIT 3 FEED WATER SYSTEM HP HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8590 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | None | 144 | 23 | No Level 2 inspections required at this time. Continue program of regular tests and overhauls. | 2014 | | |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | None | 145 | 23 | No Level 2 inspections required. Continue program of regular tests and overhauls. | 2014 | | |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | None | 146 | 23 | No Level 2 inspections required. Continue program of regular tests and overhauls. | 2014 | | |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | None | 147 | 31 | See detail below. | 2014 | 1 | $239 |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 148 | 31 | Shell side inspections and channel side for the degradation mechanisms. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 149 | 31 | Assessment of the tube plug map. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 150 | 31 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | None | 151 | 31 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 152 | 31 | Shell side inspections and channel side for the degradation mechanisms. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 153 | 31 | Assessment of the tube plug map. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 154 | 31 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes) | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | None | 155 | 31 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2014 | 2 | |

Table 10-35 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 156 | 31 | Shell side inspections and channel side for the degradation mechanisms. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 157 | 31 | Assessment of the tube plug map. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 158 | 31 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes) | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | None | 159 | 31 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2014 | 2 | |

### 10.2.2.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system – HP feedwater heat exchangers include:

**TABLE 10-36 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEED WATER SYSTEM HP FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8590 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEEDWATER PUMPING | N/A | 121 | | 3 | No capital required. | | |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 122 | 23 | 3 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 123 | 23 | 3 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | N/A | 124 | 23 | 3 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 125 | 23 | 3 | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency. | 2013 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 126 | 23 | 3 | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | N/A | 127 | 23 | 3 | Install vibration monitoring. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | N/A | 128 | | 3 | No capital required. | | |
| 1296 | 8193 | 8528 | 8611 | 8618 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 4 | N/A | 129 | 31 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8528 | 8611 | 8619 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | N/A | 130 | 31 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8528 | 8611 | 8620 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 6 | N/A | 131 | 31 | 3 | None, pending Level 2 or next inspection. | | |

### 10.2.3 Asset 8571 – Unit 3 Feedwater System - Deaerator

(Detailed Technical Assessment in Working Papers, Appendices 31 and 34)

Equipment Scope:

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8523 #3 Condensate & Feedwater System |
| Sub-Systems: | 8546 #3 Low Pressure Feedwater |
| Components: | 8571 #3 Deaerator System (Deaerator and Deaerator Storage Tank) |

#### 10.2.3.1 Description

Deaerator systems consist of two vessels, a heater (deaerator) and a storage tank (deaerator storage tank). The Unit 3 deaerator is a vertical spray type, with the deaerator mounted on the horizontal deaerator storage tank.

The deaerator and deaerator storage tank vessels are of welded construction using carbon steel with some of the deaerator internal hardware fabricated from stainless steel. The vessels are designed as per American Society of Mechanical Engineers (ASME) Boilers and Pressure Vessels Code Section VIII, Div. 1. There is one safety valve on the top of the each deaerator vessel.

The function of the deaerator is to remove oxygen and other dissolved gases in the feedwater in order to lower the potential for corrosion during the steam/water cycle. Condensate is sprayed over a cascading series of trays to maximize the surface area of the water. Bleed steam is used as a main source of steam to strip the oxygen and other non-condensable gases from the condensate. Pegging steam is provided from the auxiliary steam system. The steam and gases are vented from the top of the deaerator vessel.

The deaerated water is collected in the storage tank where steam coil heaters maintain water temperatures during off-line periods.

The deaerator storage tank is the suction tank for the boiler feedwater pumps (BFP's). High pressure (HP) feedwater heat exchangers drains are fed to the deaerator. The BFP recirculation line is fed back to the storage tank.

The deaerator storage tank is provided with two cradle type supports. One support is anchored and the other support is free to allow thermal expansion.

#### 10.2.3.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.3.3 Inspection and Repair History

The deaerator and deaerator storage tank vessels internal visual inspections and NDE of selective welds were carried out in accordance with the plant annual outage inspection plan. The inspections were mostly focused on the accessible areas. There were very limited inspections carried out on the deaerator vessels as there is no real access to the shell without removing the trays. The following is a summary of the inspection findings that were reported in the ALSTOM outage reports from the years 2001 to 2009.

**Deaerator**

- Cracks in the stainless steel liner;
- Loose trays;
- Cracks in the centre nozzle sleeve;
- Erosion of spray nozzles; and
- No evidence of cracking in the accessible shell seam welds during limited inspections.

**Deaerator Storage Tank**

- Light pitting has been observed on the inside surfaces in general, especially around the weld seams and in the bottom of shells.
- It was noted in the 2004 outage report that the hot feedwater inlet nozzle to shell attachment welds appeared to be in poor condition. These have not been repaired.
- During the 2007 outage, one small crack was found in the western most stiffener at a seam weld on the south side.

### 10.2.3.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system - deaerator is illustrated below in Table 10-37.

**TABLE 10-37 CONDITION ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 122 | 31 | No major life limiting issue observed during the past limited deaerator and deaerator storage tank inspections. Many susceptible locations have not been inspected. The corrosion fatigue issues experienced in the past are not re-occurring. Some pitting in the both deaerator and deaerator storage tank vessels and wall thinning observed in the bottom of the deaerator shells. Some erosion of spray nozzles observed. | 4 | 200000 (30) | (10) | 2020 | 2011 | 2014 | No | No | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.3.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 feedwater system – deaerator:

**TABLE 10-38 RECOMMENDED ACTIONS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 174 | 31 | Perform Level 2 inspections. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 175 | 31 | Implement ongoing inspections and performance testing based on industry practices. | 2014 | 3 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 176 | 31 | Repair the feedwater recirculation inlet nozzles at the deaerator storage tank from inside at Unit 1, if not repaired yet. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 177 | 31 | Refurbish manway seating surfaces that are in poor condition. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 178 | 31 | Monitor pitting corrosion in the both deaerator and deaerator storage tank vessels and wall thinning in the bottom of the deaerators. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 179 | 31 | Investigate the root cause of the ridges observed in Units 1&2 deaerator vessels. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 180 | 31 | Assess the significance of weld undercut that was observed in Unit 1 deaerator storage tank. | 2014 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 181 | 31 | Evaluate condition of spray nozzles that were observed eroding in Unit 3. | 2014 | 2 |

### 10.2.3.6 Risk Assessment

The risk assessment associated with the Unit 3 feedwater system - deaerator, both from a technological perspective and a safety perspective, is illustrated below in Table 10-39.

**TABLE 10-39 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM – DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | Units 1-3 Deaerators | 154 | 31 | Corrosion-fatigue, thermal fatigue, corrosion and FAC. | (10) | No real life limiting issue as per inspection to date. Additional inspections required. | 3 | B | Medium | 3 | B | Medium | Weld cracking, corrosion fatigue, wall thinning due FAC and internal hardware failure leading to functional failure. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | Units 1-3 Deaerator Storage Tanks | 155 | 31 | Corrosion-fatigue, thermal fatigue, corrosion and FAC. | (10) | No real life limiting issue as per inspection to date. Additional inspections required. | 2 | B | Low | 2 | B | Low | Weld cracking, corrosion fatigue cracking, pitting corrosion cracking and support failure. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | Units 1-3 Deaerators/ Storage Tanks | 156 | 31 | Corrosion-fatigue and thermal fatigue, | (10) | No evidence of susceptibly during limited inspection to date. Ongoing monitoring required. | 1 | D | Medium | 1 | D | Low | Catastrophic failure at seam weld. | Inspect and maintain. |

### 10.2.3.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 feedwater system – deaerator is illustrated below. Only one curve is used as the major elements of the deaerator are approximately of the same age and condition. The life curve is a plot of current and projected operating hours of usage on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

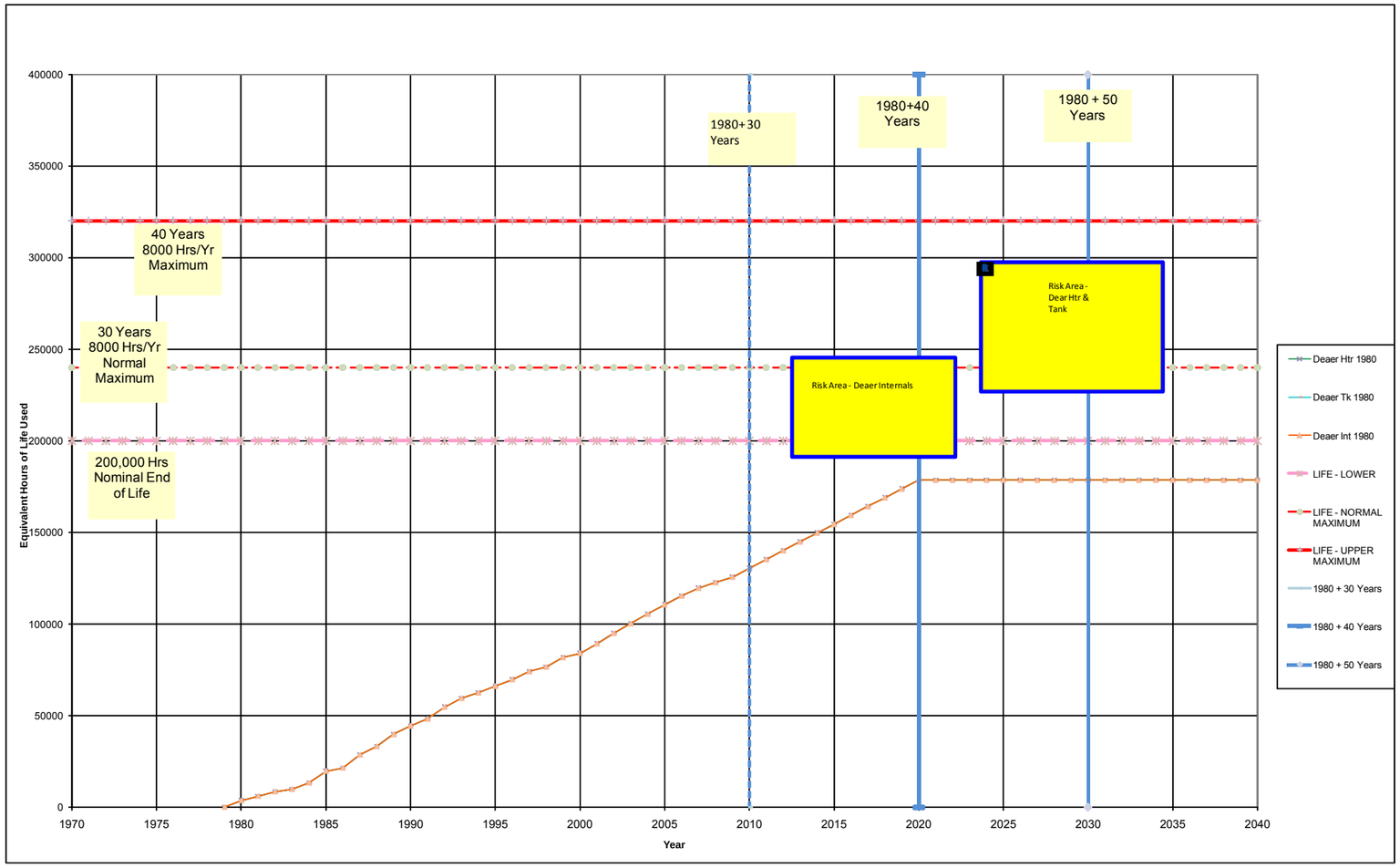



**FIGURE 10-18 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - DEAERATOR**

The curve indicates that the remaining life (RL) of the Unit 3 feedwater system - deaerator exceeds the desired life (DL) which is end date for generation of 2020, with the potential though unlikely exception of some deaerator internals. The plant inspections form an excellent base of condition information supporting the ability of the deaerator as a whole to meet the EOL date. However, there is insufficient detailed inspection information of some of the internals that are difficult to access in order to fully assess their condition. A detailed Level 2 inspection is recommended in 2014.

### 10.2.3.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-40 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-40 LEVEL 2 INSPECTIONS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 136 | 31 | NDE inspection of the areas that were not inspected is required. | 2014 | 2 | $229 |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 137 | 31 | Visual inspection for FAC damage (shiny black surface) of the susceptible areas. UT thickness measurement to be carried out if FAC damage is evident. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 138 | 31 | Inspection of all accessible shell and head surfaces for pitting, and for water streaks or signs of erosion (erosion will normally appear as a clean, pitted surface). | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 139 | 31 | Inspection of the tray stack. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 140 | 31 | Inspection of the spray valves. | 2014 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | None | 141 | 31 | Inspections for cracking Re-inspection intervals to be based on operating/inspection/repair history as per NACE recommendations and local regulations. | 2014 | 2 | |

### 10.2.3.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system - deaerator include:

**TABLE 10-41 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEEDWATER SYSTEM - DEAERATOR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | N/A | 118 | 31 | 3 | None, pending Level 2 or next inspection. | | |

### 10.2.4 Asset 8546 – Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers

(Detailed Technical Assessment in Working Papers, Appendix 24)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8528 #3 Condensate & Feedwater System |
| Sub-Systems: | 8546 #3 Low Pressure Feedwater |
| | 8801 #3 Condensate Extraction (Tables Only) |
| Components: | 8551 #3 L.P. Heater 1 |
| | 8552 #3 L.P. Heater 2 |
| | 8586 #3 LP FW Reserve |
| | 8801 #3 Condensate Extraction System |

#### 10.2.4.1 Description

The low pressure (LP) feedwater system servicing Unit 3 includes two LP feedwater heat exchangers that are referred to as LP-1 and LP-2. The primary function of the LP feedwater heat exchangers is to increase plant thermal efficiency by preheating the boiler feedwater prior entering to the deaerator.

The LP feedwater heat exchangers are horizontally mounted, 100% capacity pressure vessels of the U-tube type construction. There are two tube passes on the feedwater side and a divided flow of heating steam on the shell side of each heater.

The main components of the LP feedwater heat exchangers are shell, shell skirt, tubes, tubesheet, channel, impingement plates, tube support plates/pass partition plates/baffles, shrouds, impingement plate and channel cover. The tubesheet and channel are made from a single forging. The heat exchangers are designed according to ASME Boiler and Pressure Vessel Code Section VIII Div. 1, Heat Exchanger Institute standard for the closed feedwater heaters.

Two condensate extraction pumps service Unit 3 and are driven by 4 kV electric motors. They draw condensate from the condenser and circulate it to the low pressure feedwater heaters and deaerator. The system also includes condensate make-up and a low pressure feedwater reserve tank system to enable the unit to manage high and low water levels throughout the condensate and feedwater system.

#### 10.2.4.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.4.3 Inspection and Repair History

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these tests were not available. Leaking tubes are plugged when identified during a leak test. In addition, the tube plugging maps and history were not available. During interview with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 3.

The condensate extraction system is regularly inspected as part of the plant PM program. No significant issues have been identified with the pumps. The motors are electrically checked annually and appear to be in reasonable condition for their age. However, the motors are at an age where reliability and failure may be issues in future. The condensate extraction piping is experiencing some external corrosion, but no leaks or failures were identified.

No internal inspections of the reserve tank have been undertaken recently, due primarily to concerns with enclosed space requirements. Externally, there is some minor surface pitting evident. No significant problems or leaks were noted as having been a concern.

### 10.2.4.4 Condition Assessment

The condition assessment of the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components illustrated below in Table 10-42.

**TABLE 10-42 CONDITION ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8801 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 109 | 20 | No issues identified. | 3a | (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | Pump | 110 | 20 | Pump and motor in 1978. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | Motor | 111 | 20 | Pump and motor in 1978. No major issue identified. Annual motor test OK, but motor age an issue. | 3a | (25) | (5+) | 2020 | 2012 | | Yes | No | 1980 |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | Pump | 112 | 20 | Pump and motor in 1978. No issue identified. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | Motor | 113 | 20 | Pump and motor in 1978. No major issue identified. Annual motor test OK, but motor age an issue. | 3a | (25) | (5+) | 2020 | 2012 | | Yes | No | 1980 |
| 1296 | 8193 | 8528 | 0 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 114 | | Not reviewed. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8530 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 115 | 31 | Not reviewed. | 4 | 200000 (30) | 10 | 2020 | 2011 | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | N/A | 116 | 26 | | 4 | 200000 (30) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | N/A | 117 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm. | 4 | (25) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | N/A | 118 | 26 | No NDE inspections done. Annual cleaning and tube leak testing. Two heaters on the units may have been replaced, but no records or other interviews could confirm. | 4 | (25) | (10) | 2020 | 2011 | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8528 | 8546 | 8586 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 119 | 26 | No internal visual inspections recently. Minor external pitting corrosion. Relatively minor internal corrosion identified during interviews. No recent NDE inspections. | 4 | (60) | (20) | 2020 | 2011 | 2011 | Yes | Yes | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.4.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components:

**TABLE 10-43 RECOMMENDED ACTIONS – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 157 | 20 | See details below. | | |
| 1296 | 8193 | 8528 | 8801 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 158 | 20 | Spot check likely critical parts of piping and valving – thickness and corrosion. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8801 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | N/A | 159 | 20 | Maintain current program of ongoing inspections and overhauls. Procure a spare motor to service all three units, in the event of a failure of an existing unit. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8801 | 8536 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | N/A | 160 | 20 | Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8801 | 8537 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | N/A | 161 | 20 | Procure a spare condensate extraction motor, primarily for Units 1 & 2 but compatible with Unit 3. Continue current inspection and maintenance activities. | 2012 | 1 |
| 1296 | 8193 | 8528 | 8530 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 162 | 21 | No recommended action. | | |
| 1296 | 8193 | 8528 | 8546 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | N/A | 165 | 24 | Implement ongoing inspections and performance testing based on industry practices. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8586 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 166 | 26 | Perform Level 2 inspections on tanks – thickness checks and internals inspections. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8586 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 167 | 26 | Continue a program of ongoing inspections and compare against industry practices. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8551 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | N/A | 168 | 24 | Perform Level 2 inspections. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8552 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | N/A | 169 | 24 | Perform Level 2 inspections. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8586 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 170 | 26 | Perform Level 2 inspections on tanks – thickness checks and internals inspections. | 2011 | 2 |
| 1296 | 8193 | 8528 | 8546 | 8586 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 171 | 26 | Continue a program of ongoing inspections and compare against industry practices. | 2011 | 2 |

### 10.2.4.6 Risk Assessment

The risk assessment associated with the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components, both from a technological perspective and a safety perspective, is illustrated below in Table 10-44.

**TABLE 10-44 RISK ASSESSMENT – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8528 | 0 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | | 138 | | Not addressed. | 10 | None | | | | | | | | |
| 1296 | 8193 | 8528 | 8801 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | CE Piping/Valves | 139 | 20 | Weld failure, rupture. | 10 | None | 1 | A | Low | 1 | B | Low | Piping leak; short duration shutdown for repair. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | CE Pumps | 140 | 20 | Seal, bearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Current inspection and maintain. |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | 4 kV Condensate Extraction Pump Motor | 141 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | B | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Spare and current inspection and maintain. |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | CE Pumps | 142 | 20 | Seal, bearing, impeller failure. | 10 | None | 1 | A | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Current inspection and maintain. |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | 4 kV Condensate Extraction Pump Motor | 143 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | B | Low | 1 | B | Low | Pump failure; 0% capability reduction due to redundancy. | Spare and current inspection and maintain. |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | All LP Feedwater Heaters | 147 | 24 | SCC, thermal/ mechanical fatigue. | (10) | Life management program is required. | 1 | C | Low | 1 | B | Low | Excessive tube failure event resulting in Turbine water induction. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8586 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | LP Feedwater Reserve Tanks | 148 | 26 | Corrosion, impingement. | (20) | None | 1 | A | Low | 1 | A | Low | Major Leak, loss condensate. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8586 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | Common Feedwater Reserve Tanks | 149 | 26 | Corrosion, impingement. | (20) | None | 1 | A | Low | 1 | A | Low | Major Leak, loss condensate. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | N/A | 150 | 24 | SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue. | (10) | Could meet the desired life; however, baseline inspection required. | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | N/A | 151 | 24 | SCC, FAC, thermal/mechanical fatigue, corrosion-fatigue. | (10) | Could meet the desired life; however, baseline inspection required. | 1 | B | Low | 1 | B | Low | Tube failures, internal hardware failure and shell wall thinning due FAC and weld cracking. | Inspect and maintain. |

### 10.2.4.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 feedwater system - low pressure feedwater heat exchangers is illustrated below. One curve represents both low pressure heat exchangers which are original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

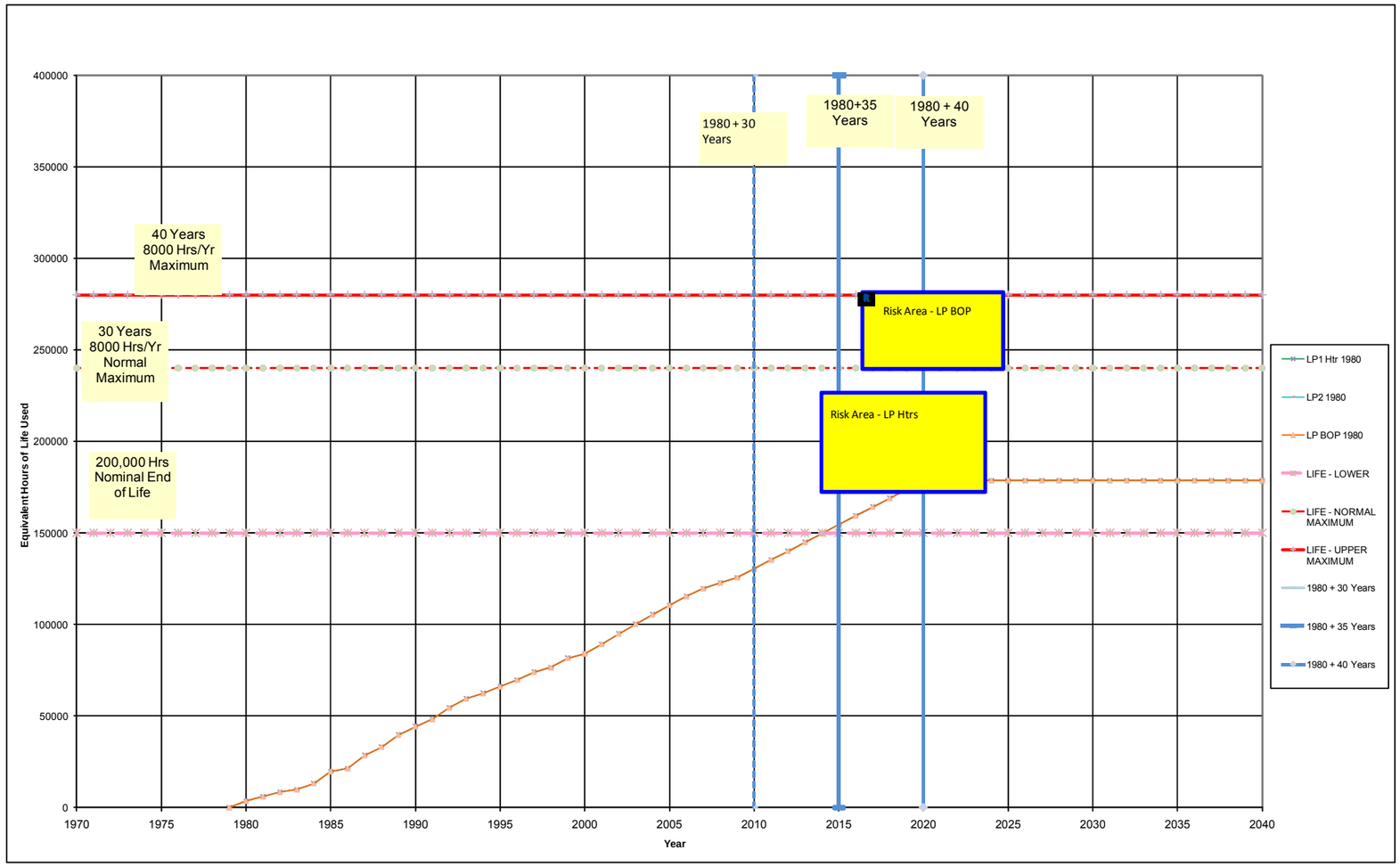



**FIGURE 10-19 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

The curve indicates that the remaining life (RL) of the Unit 3 feed water system LP heat exchangers may not be able to reach the desired life (DL) 2020 end date for generation. Given that no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is recommended for 2011.

The life cycle curve for the Unit 3 condensate extraction pumps and motors is illustrated below. One curve is used to represent the pumps and motors as they are all original equipment. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has two vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

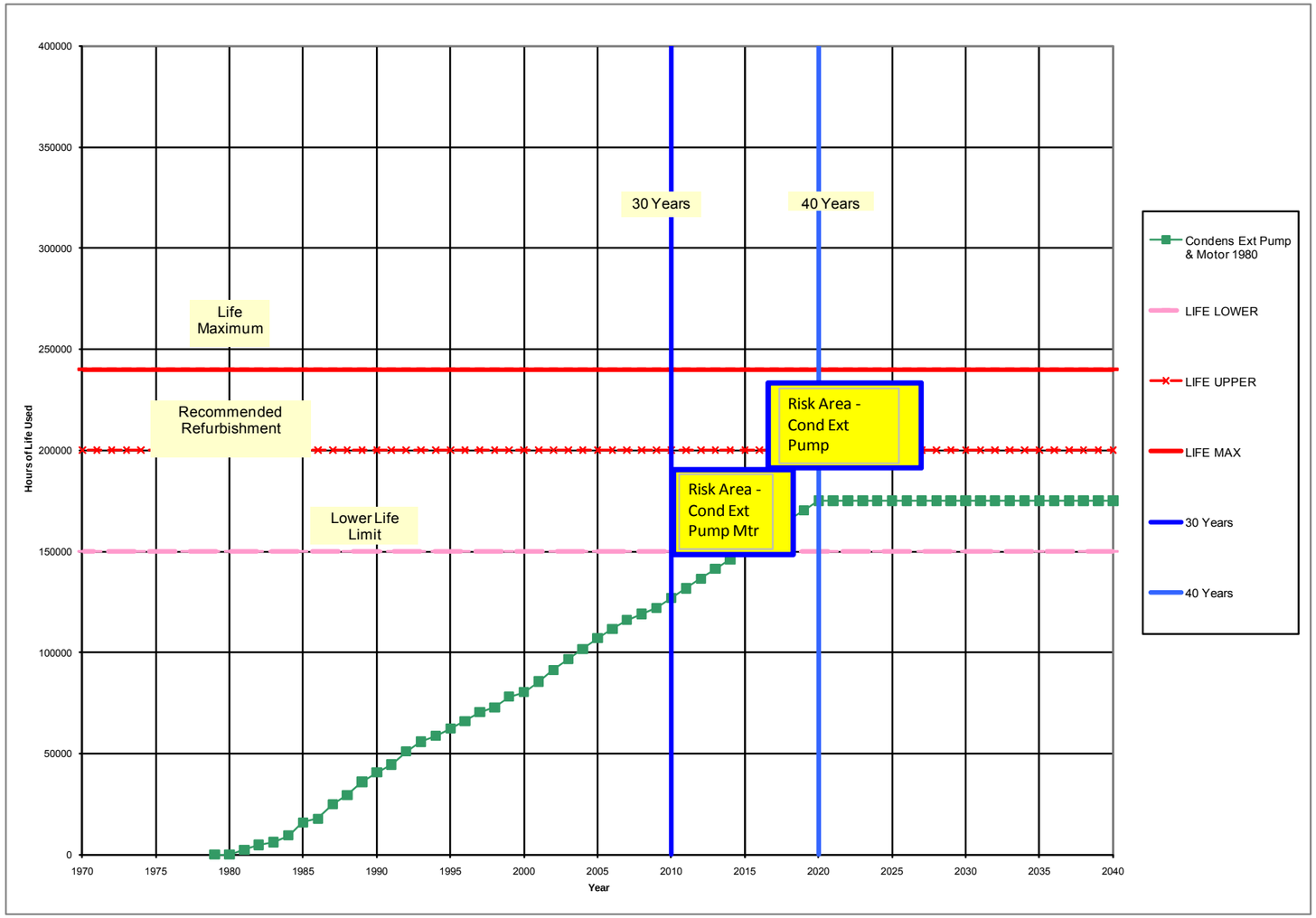



**FIGURE 10-20 LIFE CYCLE CURVE – UNIT 3 FEEDWATER SYSTEM - CONDENSATE EXTRACTION SYSTEM**

The curves indicate that the remaining life (RL) of the condenser condensate extraction pumps and motors can likely be able to reach the desired life (DL) 2020 end date for generation. The condensate extraction pump motors are expected however to be entering a period of higher unreliability.

### 10.2.4.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-45 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-45 LEVEL 2 INSPECTION – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 0 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | None | 117 | 20 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8528 | 8801 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYST | CONDENSATE EXTRACTION SYST | None | 118 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | | |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | None | 119 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | | |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | None | 120 | 20 | No Level 2 inspections required at this time. Continue program of regular inspections and overhauls. | | | |
| 1296 | 8193 | 8528 | 8530 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | None | 121 | 20 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | None | 124 | | See details below. | 2011 | 3 | $105 |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | None | 125 | 24 | Shell side inspections and channel side for the degradation mechanisms. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | None | 126 | 24 | Assessment of the tube plug map. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | None | 127 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | None | 128 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | None | 129 | 24 | Shell side inspections and channel side for the degradation mechanisms. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | None | 130 | 24 | Assessment of the tube plug map. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | None | 131 | 24 | ET inspection of tubes to assess the present condition (metallurgical evaluation may also be required depending upon the condition of the tubes). | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | None | 132 | 24 | NDE inspection the major welds (seam, supports and nozzle welds) for the degradation mechanisms. PT or Magnetic particle testing (MT) or Conventional UT or Phased array (focused) can be used depending upon location. | 2011 | 2 | |
| 1296 | 8193 | 8528 | 8546 | 8586 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | None | 133 | 26 | Inspections of interior wall inspections and thickness measurements of walls and impaired major welds. Internals visual inspection. | 2011 | 3 | |

### 10.2.4.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 feedwater system – low pressure feedwater heat exchangers (and associated condensate extraction system) components include:

**TABLE 10-46 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FEEDWATER SYSTEM - LOW PRESSURE FEEDWATER HEAT EXCHANGERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 0 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | N/A | 105 | | 3 | No capital required. | | |
| 1296 | 8193 | 8528 | 8801 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION SYSTEM | CONDENSATE EXTRACTION SYSTEM | N/A | 106 | 20 | 3 | No capital required. | | |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P NORTH | CONDENSATE EXTRACTION P/P NORTH | N/A | 107 | 20 | 3 | Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatable with all units. | 2014 | 3 |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION P/P SOUTH | CONDENSATE EXTRACTION P/P SOUTH | N/A | 108 | 20 | 3 | Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatable with all units. | 2014 | 3 |
| 1296 | 8193 | 8528 | 8530 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSATE MAKE UP SYSTEM | CONDENSATE MAKE UP SYSTEM | N/A | 109 | | 3 | No capital required. | | |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | N/A | 112 | 26 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8528 | 8546 | 8586 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE F.W. RESERVE | N/A | 113 | 26 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8528 | 8546 | 8551 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 1 | N/A | 114 | 24 | 3 | None, pending Level 2 or next inspection. | | |
| 1296 | 8193 | 8528 | 8546 | 8552 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE HEATER 2 | N/A | 115 | 24 | 3 | None, pending Level 2 or next inspection. | | |

### 10.2.5 Asset 271677 – Unit 3 Condenser

(Detailed Technical Assessment in Working Papers, Appendix 22)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8194 #1 Turbine & Generator |
| Sub-Systems: | 8223 # 3 Turbine & Condenser |
| Components: | 271677 #3 Condenser |
| | 8252 #3 Condenser Air Extraction |

#### 10.2.5.1 Description

The Unit 3 condenser is a shell and tube type heat exchanger with two passes. There are two tube bundles in a single shell. The inlet and the outlet waterboxes are divided. Each tube bundle has an air removing zone (ARZ) in the middle of the bundle. There are 2 x 100% liquid ring vacuum pumps to remove the air and non condensable gases from the condenser shell. The pumps are designed to allow the unit to run at full vacuum with only one pump operating. Each is equipped with a nominally 70 kW, 600 V motor. The condenser has a stainless steel metal bellow joint between the condenser shell and the turbine lower exhaust casing to compensate for turbine and condenser expansion.

The condenser cooling water is a combination of sea water and fresh water. The carbon steel waterbox material is protected by an epoxy coating and a sacrificial anodic system. The condenser waterboxes are equipped with a back wash system for cleaning the tubes internally while the unit is in operation. Nylon brushes are used to clean the tubes prior to the condenser lay-up.

The condenser was designed, fabricated and supplied by Foster Wheeler in 1979.

#### 10.2.5.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Next Major Overhaul/Inspection | 2016 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.5.3 Inspection and Repair History

The Unit 3 condenser is in good shape for its age. The number of plugged tubes is quite low, and the rate of increase in plugging has remained steadily low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

As of 2000, 7.8% of the total number of tubes was plugged and by December 2010, 8.4% were plugged. This indicates that the in-service wear/erosion degradation of 0.6% over 10 years is very slow. In April 2003 only 13 out of the 240 tubes were plugged in the ARZ. By December 2010, 14 tubes were plugged. The pattern is random indicating no condensate grooving is present.

The 2003 and 2006 GE Betz inspection reports confirm that both shell and hotwell are in good condition. During 2003 to 2004, the waterboxes were confirmed as having the epoxy lining in good condition and the condition of the water boxes to be well managed in general.

The two condenser air extraction vacuum pumps and system are original equipment and approaching their expected end of life. No major issues were identified with achieving the required condenser back pressure at turbine full load or during unit start up. The pumps and motors are serviced yearly under the plant PM program. The plant is modifying the existing vent system to enable venting externally in order to eliminate the exhaust of its moisture into the powerhouse.

### 10.2.5.4 Condition Assessment

The condition assessment of the Unit 3 condenser is illustrated below in Table 10-47.

**TABLE 10-47 CONDITION ASSESSMENT – UNIT 3 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 2 | 22 | Excellent condition, with exception of aging pumps. | 4 | 200000 (40) | 20 | 2020 | 2011 | 2016 | Yes | Yes | 1980 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 0 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | CONDENSER AIR EXTRACTION | N/A | 3 | 22 | End of Life near. Replace as failure occurs or imminent. | 10 | 150000 (30) | 2 | 2020 | 2011 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8892 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUMPUMP NORTH | CONDENSER AIR VACUUM PUMP NORTH | N/A | 4 | 22 | Functional. Near end of life | 10 | 150000 (30) | 2 | 2020 | 2011 | 2016 | No | No | 1980 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8893 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUM PUMP SOUTH | CONDENSER AIR VACUUM PUMP SOUTH | N/A | 5 | 22 | Functional. Near end of life | 10 | 150000 (30) | 2 | 2020 | 2011 | 2016 | No | No | 1980 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 99000295 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR REMOVAL SYSTEM | CONDENSER AIR REMOVAL SYSTEMS | N/A | 6 | 22 | Vacuum pumps near end of life. Exhaust location an issue. | 10 | 200000 (30) | 2 | 2020 | 2011 | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 8223 | 271677 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | TURBINE CONDENSER | N/A | 7 | 22 | Condition is very good. 2010 tubes plug survey shows 8.4 % of tubes plugged vs 7.8% in 2000. More than Units 1 and 2, likely is due to the mechanical damage. No condensate grooving on the tube OD in the air removing zone. Minor wear and tear of waterboxes and condenser shell. The condenser steel piping at inlet and outlet has some patching evident on some units. | 3a | 300000 (50) | 20 | 2020 | 2011 | 2012 | Yes | Yes | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.5.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 condenser

**TABLE 10-48 RECOMMENDED ACTIONS – UNIT 3 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8223 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 4 | 22 | Develop a ongoing program of monitoring CW inlet/outlet pipe conditions. | 2011 | 2 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | CONDENSER AIR EXTRACTION | N/A | 5 | 22 | See details below. | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUM PUMP NORTH | CONDENSER AIR VACUUM PUMP NORTH | N/A | 6 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump. | 2011 | 2 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUM PUMP SOUTH | CONDENSER AIR VACUUM PUMP SOUTH | N/A | 7 | 22 | Inspect CW Vacuum pump and refurbish or replace motor and pump. | 2011 | 2 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR REMOVAL SYSTEM | CONDENSER AIR REMOVAL SYSTEM | N/A | 8 | 22 | Add new vent line to outside. | 2011 | 2 |
| 1296 | 8193 | 8194 | 8223 | 271677 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | TURBINE CONDENSER | N/A | 9 | 22 | No specific recommended actions, maintain annual inspection and tube mapping. | 2011 | 2 |

### 10.2.5.6 Risk Assessment

The risk assessment associated with the Unit 3 condenser, both from a technological perspective and a safety perspective, is illustrated below in Table 10-49.

**TABLE 10-49 RISK ASSESSMENT – UNIT 3 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 5 | | See detail below. | | | | | | | | | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 0 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | CONDENSER AIR EXTRACTION | N/A | 6 | | See detail below. | 10 | | | | | | | | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8892 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP NORTH | CONDENSER AIR VAC PUMP NORTH | Condenser Vacuum Pumps & System | 7 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff decrease while replaced. | Maintain, refurbish or replace as required. |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8893 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP SOUTH | CONDENSER AIR VAC PUMP SOUTH | Condenser Vacuum Pumps & System | 8 | 22 | Mechanical failure/leaks. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff decrease while replaced. | Maintain, refurbish or replace as required. |
| 1296 | 8193 | 8194 | 8223 | 8252 | 99000295 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR REMOVAL SYSTEM S | CONDENSER AIR REMOVAL SYSTEM S | Condenser Air Vent | 9 | 22 | Corrosion, erosion. | 2 | None | 1 | A | Low | 1 | A | Low | Derate/Eff decrease while repaired. | Maintain, refurbish or replace as required. |
| 1296 | 8193 | 8194 | 8223 | 271677 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | TURBINE CONDENSER | N/A | 10 | | Erosion, corrosion. | 20 | None | 2 | B | Low | 2 | A | Low | Major seawater leak to condenser - unit shutdown. Water cleanup. | Inspect and Repair. Track history. |

### 10.2.5.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 condenser is illustrated below. One curve is used as the major elements of the condenser are of the same age and condition. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

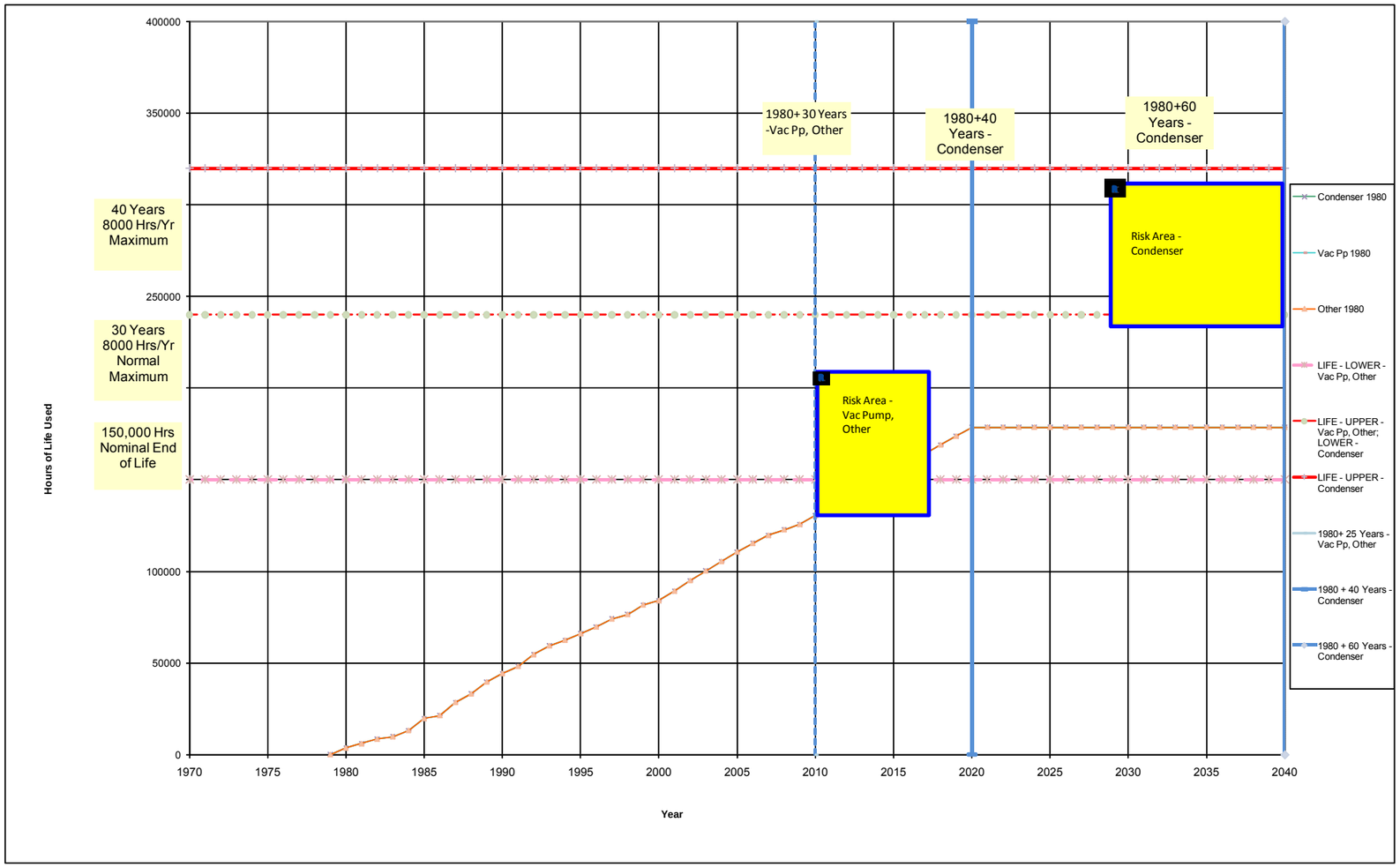



**FIGURE 10-21 LIFE CYCLE CURVE – UNIT 3 CONDENSER**

With the exception of the vacuum pumps, the curves indicate that the remaining life (RL) of the Unit 3 condenser can easily reach the desired life (DL) 2020 end date for generation. Additional information at the 2013 and 2016 turbine inspections should further confirm the condition. The equipment is original and is likely at or near end of life.

### 10.2.5.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-50 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-50 LEVEL 2 INSPECTION – UNIT 3 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 1 | 22 | NDE spot check inspection of major inlet and outlet pipes. Condensers themselves continue ongoing maintenance and inspection. | 2011 | 2 | $6 |
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | None | 2 | 22 | At next turbine valve overhaul in 2013, the inspection work or repairs (within the plant inspection and maintenance work) should be carried out, including:<br>- Leak test and update the tubesheet maps for both the waterboxes.<br>- Check the inlet waterboxes for tubes with water erosion at the tube inlets. Where required, install 10'' plastic inserts into the tubes to protect them from further wall loss or loss of tube.<br>- Inspect condenser hotwell internal piping and supports for steam and water erosion. Investigate and repair as necessary.<br>- Inspect hotwell drip drains for eroded or missing baffle plates. Replace if eroded or missing. | 2013 | 2 | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 0 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | CONDENSER AIR EXTRACTION | None | 3 | 22 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8892 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUM PUMP NORTH | CONDENSER AIR VACUUM PUMP NORTH | None | 4 | 22 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8893 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VACUUM PUMP SOUTH | CONDENSER AIR VACUUM PUMP SOUTH | None | 5 | 22 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 99000295 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR REMOVAL SYSTEMS | CONDENSER AIR REMOVAL SYSTEMS | None | 6 | 22 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8194 | 8223 | 271677 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | TURBINE CONDENSER | None | 7 | 22 | No Level 2 inspections or testing is required. | | | |

### 10.2.5.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 condenser include:

**TABLE 10-51 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 CONDENSER**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | N/A | 5 | 22 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 0 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR EXTRACTION | CONDENSER AIR EXTRACTION | N/A | 6 | 22 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8892 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP NORTH | CONDENSER AIR VAC PUMP NORTH | N/A | 7 | 22 | 3 | Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room. | 2015 | 1 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8893 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP SOUTH | CONDENSER AIR VAC PUMP SOUTH | N/A | 8 | 22 | 3 | Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room. | 2015 | 1 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 99000295 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR REMOVAL SYSTEM S | CONDENSER AIR REMOVAL SYSTEM S | N/A | 9 | 22 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 8223 | 271677 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER | TURBINE CONDENSER | N/A | 10 | 22 | 3 | No capital required. | | |

### 10.2.6 Asset 8777 – Unit 3 FD Fans (and System)

(Detailed Technical Assessment in Working Papers, Appendix 19)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8336 #3 Boiler Plant |
| Sub-Systems: | 8387 #3 Boiler Air System |
| | 8437 #3 Boiler Gas System |
| | 8460 #3 Boiler Fuel Firing System |
| | 8461 #3 Boiler Heavy oil System |
| | 8462 #3 Boiler Light Oil System |
| Components: | 8782 #3 Boiler FD Fan System<br>8392 #3 Boiler FD Fan East<br>8393 #3 Boiler FD Fan West<br>8404 # 3Boiler Steam Air Heater East<br>8405 #3 Boiler Steam Air Heater West<br>8410 #3 Boiler Main Air Heater East<br>8411 #3 Boiler Main Air Heater West |
| | 8464 #3 Boiler Heavy Oil Pump East<br>8465 #3 Boiler Heavy Oil Pump West<br>8468 #3 Boiler Heavy Oil Pump steam, valves and pipe<br>8471 #3 Boiler Heavy Oil Firing<br>7740 #3 Boiler Light Oil Pump East<br>7741 #3 Boiler Light Oil Pump West |
| | 8429 #3 Boiler Air Supply Seal Air<br>8432 #3 Boiler Scanner Air System |

#### 10.2.6.1 Description

The Unit #3 Babcock and Wilcox boiler at Holyrood has two 50% duty 4KV AC motor driven Howden forced draft fans (east/west) which provide the combustion air for both the heavy #6 residual oil and the lighter #2 ignition oil. These fans are centrifugal in design and draw air from the top of the boiler house through ducts specifically connected to each fan inlet.

The air flow required for combustion is regulated by the use of variable inlet vanes which allow the required amount of air into the boiler furnace to ensure the fuel oil is completely burned. The FD fan inlet vanes are controlled automatically either by the boiler controlled DCS system or manually by the operator if required.

In addition, each of the FD fans has a set of steam coil air heaters and a rotating Ljungstrom air heater to heat the air used in the combustion process. The combustion air is heated prior to being admitted to the furnace windbox in order to improve fuel firing and also to reduce back end corrosion. Before using the steam coil air heater to heat the combustion air, at least one boiler in the plant must be generating sufficient steam for this function.

**Asset 8437 Boiler #3 Flue Gas System:**

The Unit 3 boiler gas passes from the economizer through the flue gas ductwork to the stack breeching. The duct work design is consistent with a steam generator built in the late 1970's.

**Asset 8460 Fuel Oil Firing**

The Unit 3 Babcock and Wilcox boiler heavy oil system supplies the 9 main burners with residual oil that is supplied from any of the 4 main heavy fuel oil storage tanks to the fuel oil day tank. The viscosity (SSU) of this fuel is high and therefore heat is required in order for it to flow. A series of steam heaters are installed in the storage tanks and steam heat tracing is provided on all of the main fuel oil lines feeding both the fuel oil day tank and the unit pumping and heating set. The main fuel oil is gravity fed from both the main fuel oil storage tanks to the day tanks as well from the day tank to the unit main heavy oil pumping and heating set.

Unit 3 is also equipped with 9 light oil (#2 fuel oil) igniters providing an ignition source for each main burner. The ignition oil (# 2 fuel oil) is gravity fed from the light oil fuel oil tanks to the Unit #3 light oil pumping skid.

**Asset 8426 Boiler Air Supply Seal Air and Scanner Air**

Each burner requires a flame scanner to be used to determine that a flame associated with a particular burner is either in or out of service, depending on the firing requirements. All of these scanners have electronic circuitry in the scanner heads which must be kept cool relative to the high ambient temperatures near the boilers. In order to accomplish the cooling, two 100% duty fans (north/south) are located externally and totally removed from the FD fan discharge ducts (which is different from Units 1 and 2).

### 10.2.6.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

| | |
|---|---|
| Max Hours Ops – 1986 to Dec 2009 | 113 |
| Max Hrs - 1986 to Dec 2015 | 142 |
| Max Hrs – 1986 to Gen End Date Dec 2020 | 164 |

#### 10.2.6.3 Inspection and Repair History

Based on the Alstom report for 2009, Unit 3 FD fans were inspected during the annual overhaul and very little damage was noted from 2008. A complete evaluation of both fans was conducted in 2008 by Fan Dynamics out of Cambridge Ontario. Both FD fans at that time were deemed to be in good condition.

In 2009, an inspection of Unit 3 east and west Ljungstrom air heaters was completed as part of the annual overhaul. Both of these air heaters had some repair work completed. Alstom determined that in the future, more extensive work may be needed on the cold end elements, especially on the east unit.

The combustion steam coils were reported to have no damage. However, a long standing Unit 3 full load limitation resulting in excessive FD fan motor amps was identified with no specific cause being substantiated. Additional operational evaluations are needed to identify the root cause.

The unit has experienced significant forced draft system vibration, as a consequence of the original ductwork design. Flow induced turbulence in ductwork causing vibration has the potential to result in significant damage to forced draft fans and in cracks in the ductwork. The plant has plans to modify the ductwork system in an effort to reduce vibration levels caused by air flow turbulence and also to improve overall noise and efficiency. These changes are strongly supported.

**Asset 8437 Boiler #3 Flue Gas System:**

During yearly plant major or minor overhauls, all of the ductwork has been inspected by Alstom maintenance staff. Reports obtained from the plant indicate that due diligence has been carried out to ensure the integrity of the ductwork and any repairs were completed at the time of inspection. Structural supports are inspected and all have been deemed to be in good condition and will last for the foreseeable future.

Sootblowing system has minor maintenance carried out during normal operation.

**Asset 8460 Fuel Oil Firing**

Reports from the plant regarding the condition of light and heavy systems were not available. However, they appear to have been properly maintained. Although these two systems are critical to unit operation, replacement parts or systems will typically be available for the life of a plant and therefore not considered to be life limiting.

**Asset 8426 Boiler Air Supply Seal Air and Scanner Air**

These two auxiliary systems are totally external to the main boiler and have limited control circuitry to ensure they operate correctly. Any piping or hose leaks can be repaired at minimum costs as long as proper maintenance activity is carried out. Replacement of flame scanner heads is the single most costly expenditure if the system fails. Both of these systems appear to be well maintained.

### 10.2.6.4 Condition Assessment

The condition assessment of the Unit 3 FD fans (and system) is illustrated below in Table 10-52.

**TABLE 10-52 CONDITION ASSESSMENT – UNIT 3 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8387 | 0 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 76 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 77 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8429 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY SEAL AIR | N/A | 78 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8432 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 79 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8433 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 80 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 81 | 19, 30 | Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 82 | 19, 30 | Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 83 | 19, 30 | Both FD fans at that time were deemed to be in good condition. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Motors | 84 | 25 | Inspected yearly and repairs completed. | 3a | 200000 (30) | (5) | 2020 | 2011 | | Yes | No | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Motors | 85 | 25 | Inspected yearly and repairs completed. | 3a | 200000 (30) | (5) | 2020 | 2011 | | Yes | No | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 86 | 19, 30 | No damage observed in 2009. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8404 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 87 | 19, 30 | No damage observed in 2009. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8405 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 88 | 19, 30 | No damage observed in 2009. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 89 | 19, 30 | Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8410 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 90 | 19, 30 | Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8411 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 91 | 19, 30 | Some repair work in 2009 and more extensive work likely in future years on the cold end elements. Inspected yearly and repairs completed. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8437 | 0 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 92 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8437 | 8438 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 93 | 19, 30 | Inspected yearly and repairs completed. | 3a | 200000 (40) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 94 | 17 | Inspected yearly and repairs completed as required. | 4 | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8460 | 0 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 95 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8460 | 8461 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER HEAVY OIL SYSTEM | N/A | 96 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8460 | 8484 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL SYSTEM | N/A | 97 | 19 | Inspected yearly and repairs completed as required. | 3a | 200000 (30) | 10 | 2020 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8503 | 0 | 0 | 3 | BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 98 | | Not reviewed in detail - primarily unit heaters from good to poor condition. New source needed after close of generation. | 4 | 200000 (30) | 10 | 2041 | 2011 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8337 | 0 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 102 | 17 | No recent inspections. Visual walkdown indicated no issues. | 4 | 60 | (30) | 2041 | 2011 | 2011 | Yes | Yes | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.
3. The ability of the FD fans east and west to meet a 2020 EOL date may be affected if planned duct reconfiguration is not undertaken.

### 10.2.6.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 FD fans (and system).

**TABLE 10-53 RECOMMENDED ACTIONS – UNIT 3 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8387 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 120 | 19,30 | Continue routine inspection, maintenance and overhaul - evaluating air heater hot end baskets; connecting installed FD fans vibration probes to online monitoring system; refurbish and use the furnace exit thermoprobe during start-up activities to avoid distortion and overheating of the secondary superheater and reheater sections tubes. | 2010 | 1 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 121 | 19,30 | No recommended action. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY SEAL AIR | N/A | 122 | 19,30 | No recommended action. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 123 | 19,30 | No recommended action. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8433 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 124 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 125 | 19,30, 25 | Maintain ongoing inspection and maintenance programs. Maintain a spare motor be maintained to service all three units, in the event of a failure of an existing unit. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 126 | 19,30, 25 | No recommended action. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 127 | 19,30, 25 | No recommended action. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 128 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 129 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 130 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 131 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 132 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8788 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 133 | 19,30 | Continue current inspection and maintenance activities. | 2010 | 2 |
| 1296 | 8193 | 8336 | 8437 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 134 | 19,30 | See details below. | | |
| 1296 | 8193 | 8336 | 8437 | 8438 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 135 | 19,30 | Inspect ductwork during annual inspections for excessive corrosion. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8437 | 8452 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 136 | 19 | Update obsolete controls. Evaluate/implement Intelligent Sootblowing (ISB) to reduce sootblowing energy consumption and mechanical damage impacts. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8437 | 8452 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 137 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8460 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 138 | 19 | No recommended action. | | |
| 1296 | 8193 | 8336 | 8460 | 8461 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER HEAVY OIL SYSTEM | N/A | 139 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8460 | 8484 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL SYSTEM | N/A | 140 | 19 | Continue yearly inspections and repair work. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8503 | 0 | 3 | BOILER PLANT | BOILER AUXILIARY STEAM & CONDENSATE | BOILER AUXILIARY STEAM & CONDENSATE | N/A | 141 | | Refurbish and replace unit heaters as required. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8503 | 8504 | 3 | BOILER PLANT | BOILER AUXILIARY STEAM MAIN | BOILER AUXILIARY STEAM MAIN | N/A | 142 | | Refurbish as required. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8503 | 8510 | 3 | BOILER PLANT | BOILER AUXILIARY STEAM | BOILER AUXILIARY STEAM | N/A | 143 | | Plan to replace as building heating source. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8503 | 8543 | 3 | BOILER PLANT | AUXILIARY STEAM CONDENSATE | AUXILIARY STEAM CONDENSATE | N/A | 144 | | Refurbish as required. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8337 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 145 | 17 | Visually inspect difficult to access areas. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8337 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 146 | 30 | Continue present inspection and maintenance program. Evaluate a preventive replacement of the boiler expansion joints. | 2011 | 2 |
| 1296 | 8193 | 8336 | 8337 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 147 | | Evaluate corrosion on the steel structure and hangers in the boilers penthouse areas during the boiler routine maintenance and inspection activities. Review condition of the boiler refractory to assess the requirement for replacement during the boiler routine maintenance and inspection activities. | 2011 | 2 |

### 10.2.6.6 Risk Assessment

The risk assessment associated with the Unit 3 FD fans (and system), both from a technological perspective and a safety perspective, is illustrated below in Table 10-54.

**TABLE 10-54 RISK ASSESSMENT – UNIT 3 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8336 | 8387 | 0 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | | 103 | | See detail below. | | | | | | | | | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 104 | | See detail below. | | | | | | | | | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8429 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY SEAL AIR | Scanner & Seal Air | 105 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | A | Low | Worst case - short duration shutdown for repair. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8432 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | Scanner & Seal Air | 106 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | A | Low | Worst case - short duration shutdown for repair. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8433 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 107 | | Not addressed. | 10 | None | | | | | | | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 108 | | See detail below. | 10 | None | | | | | | | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Unit #3 LP FD Fan | 109 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Unit #3 LP FD Fan | 110 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | B | Low | 1 | B | Low | Derate by 50% for short period. Consider spare motor. | Spare and current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | 4 kV Forced Draft Fan Motor | 111 | 25 | Electrical fault, mechanical fatigue, ops error. | (5) | None | 2 | C | Medium | 2 | C | Medium | Loss 60% of 1 unit generation and damages. | Spare and current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | 4 kV Forced Draft Fan Motor | 112 | 25 | Electrical fault, mechanical fatigue, ops error. | (5) | None | 2 | C | Medium | 2 | C | Medium | Loss 60% of 1 unit generation and damages. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8787 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | | 113 | | Not addressed. | | None | | | | | | | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8404 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | Unit #3 Steam Preheat Coils | 114 | 19 | Corrosion, erosion, mechanical distortion. | 10 | None | 1 | A | Low | 1 | A | Low | Short term shutdown for repairs, derated or run at increased impact. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8405 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | Unit #3 Steam Preheat Coils | 115 | 19 | Corrosion, erosion, mechanical distortion. | 10 | None | 1 | A | Low | 1 | A | Low | Short term shutdown for repairs, derated or run at increased impact. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8788 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | APH Ductwork – Gas & Air | 116 | 19 | Corrosion, erosion thinning. | 10 | None | 2 | A | Low | 2 | A | Low | Short duration shutdown for repair/patch. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8410 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | Unit #3 APH | 117 | 19 | Corrosion, mechanical failure. | 10 | None | 1 | B | Low | 1 | B | Low | 50% shutdown for maintenance and repairs. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8411 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | Unit #3 APH | 118 | 19 | Corrosion, mechanical failure. | 10 | None | 1 | B | Low | 1 | B | Low | 50% shutdown for maintenance and repairs. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8437 | 0 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 119 | 19,20 | Leaks into powerhouse. | 10 | None | 3 | B | Medium | 3 | B | Medium | Overpressure. | Maintenance, inspection. |
| 1296 | 8193 | 8336 | 8437 | 8438 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 120 | 19,20 | Leaks into powerhouse. | 10 | None | 3 | B | Medium | 3 | B | Medium | Duct split/corrosion. | Maintenance, inspection. |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 121 | | Mechanical failure. | 10 | None | 2 | B | Low | 2 | B | Low | Steam leak. Tube erosion. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8460 | 0 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | Fuel Feed System | 122 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | C | Low | Derate for short period. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8460 | 8461 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER HEAVY OIL SYSTEM | N/A | 123 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | C | Low | Derate for short period. Safety. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8460 | 8484 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL SYSTEM | N/A | 124 | 19 | Mechanical fatigue, corrosion, ops error. | 10 | None | 1 | A | Low | 1 | C | Low | Derate for short period. Safety. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8503 | 0 | 0 | 3 | BOILER PLANT | BOILER AUXILIARY STEAM AND CONDENSATE | BOILER AUXILIARY STEAM AND CONDENSATE | N/A | 125 | | Mechanical failure. | (5) | None | 3 | A | Low | 3 | B | Medium | Steam leak. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8337 | 0 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | N/A | 129 | 17 | Mechanical failure. | 20 | None | 1 | D | Medium | 1 | D | Low | Structure collapse. | Maintain and inspect. |

### 10.2.6.7 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. One curve is required to represent the all elements given all is original equipment. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

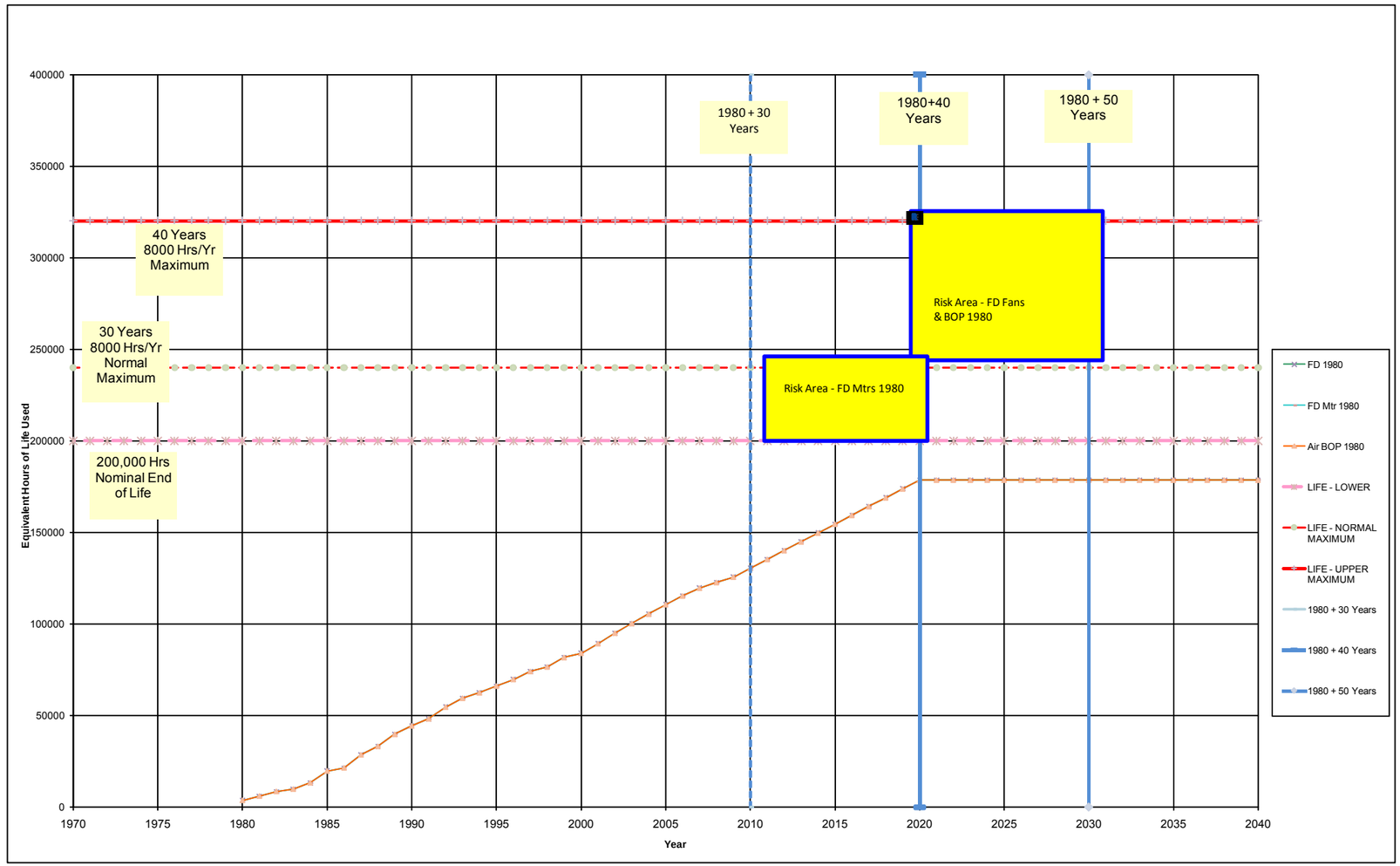



**FIGURE 10-22 LIFE CYCLE CURVE – UNIT 3 FD FANS (AND SYSTEM)**

The curves indicate that the remaining life (RL) of the Unit 3 FD fans (and system) are likely able to meet or exceed the desired life (DL) 2020 end date for generation. The age of the large 4 kV motors makes them a logical cost-effective candidate for sparing to ensure reliability, although plant testing/monitoring programs are effectively monitoring their status.

### 10.2.6.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-55 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-55 LEVEL 2 INSPECTION – UNIT 3 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8387 | 0 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | None | 86 | 19 | No Level 2 inspections or testing is required. | 2011 | | $0 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | None | 87 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8429 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY SEAL AIR | None | 88 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8432 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | None | 89 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8433 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | None | 90 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | None | 91 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | None | 92 | 19 | No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. | | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | None | 93 | 19 | No Level 2 inspections or testing is required on fan or 4 kV Motors, provided the current inspection and maintenance program is maintained. | | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | None | 94 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8404 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | None | 95 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8405 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | None | 96 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | None | 97 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8410 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | None | 98 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8411 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | None | 99 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8437 | 0 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | None | 100 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8437 | 8438 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | None | 101 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | None | 102 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8460 | 0 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | None | 103 | 19 | No Level 2 inspections or testing is required. | | | |

Table 10-55 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8460 | 8461 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER HEAVY OIL SYSTEM | None | 104 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8460 | 8484 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL SYSTEM | None | 105 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8503 | 0 | 0 | 3 | BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | None | 106 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8503 | 8504 | 0 | 3 | BOILER PLANT | BOILER AUX. STEAM MAIN | BOILER AUX. STEAM MAIN | None | 107 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8503 | 8510 | 0 | 3 | BOILER PLANT | BOILER AUXILIARY STEAM | BOILER AUXILIARY STEAM | None | 108 | 19 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8503 | 8543 | 0 | 3 | BOILER PLANT | AUXILIARY STEAM CONDENSATE | AUXILIARY STEAM CONDENSATE | None | 109 | | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8336 | 8337 | 0 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | None | 110 | | Level 2 - Visual Inspection of near rood structure | 2011 | 2 | $3 |

### 10.2.6.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 FD fans (and system) include:

**TABLE 10-56 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 FD FANS (AND SYSTEM)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8387 | 0 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | N/A | 73 | 19 | 3 | Upgrade air ducts to reduce vibration, improve efficiency. | 2013 | 1 |
| 1296 | 8193 | 8336 | 8387 | 8426 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY (A/H TO | N/A | 74 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8429 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SUPPLY SEAL AIR | N/A | 75 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8426 | 8432 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER SCANNER AIR SYSTEM | N/A | 76 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8433 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER WINDBOX | N/A | 77 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8782 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | N/A | 78 | 19 | 3 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | N/A | 79 | 19 | 3 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | N/A | 80 | 19 | 3 | Install vibration monitoring. | 2012 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8787 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER | N/A | 81 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8404 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER EAST | N/A | 82 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8787 | 8405 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER STEAM AIR HEATER WEST | N/A | 83 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER | N/A | 84 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8410 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER EAST | N/A | 85 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8387 | 8788 | 8411 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER MAIN AIR HEATER WEST | N/A | 86 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8437 | 0 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS SYSTEM | N/A | 87 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8437 | 8438 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER GAS PASSES | N/A | 88 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | N/A | 89 | 19 | 3 | FD fan ductwork modifications. | 2012 | 3 |
| 1296 | 8193 | 8336 | 8460 | 0 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER FUEL FIRING SYSTEM | N/A | 90 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8460 | 8461 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER HEAVY OIL SYSTEM | N/A | 91 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8460 | 8484 | 0 | 3 | BOILER PLANT | BOILER FUEL FIRING SYSTEM | BOILER LIGHT OIL SYSTEM | N/A | 92 | 19 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8503 | 0 | 0 | 3 | BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | N/A | 93 | 19 | 3 | New building heating system | 2015-2020 | 2 |

### 10.2.7 Asset 8448 – Unit 3 Stacks and Breeching

(Detailed Technical Assessment in Working Papers, Appendix 17)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8336 #3 Boiler Plant |
| Sub-Systems: | 8437 #3 Boiler Gas System |
| Components: | 8448 #3 Boiler Stack<br>271682 – Stack Breeching |

#### 10.2.7.1 Description

The Unit 3 stack is constructed from reinforced concrete and contains a steel liner with some sections constructed from stainless steel and the remaining sections constructed from carbon steel. The stack breeching is the insulated steel ductwork that conveys the hot flue gas from the boiler air preheater to the stack. The stack was added in 1977.

#### 10.2.7.2 History

| Description | Stack Calendar Life | Operating Hours (Equiv Op Yrs) since Installation to 2009 | Operating Hours (Equiv Op Yrs) to 2015/2020 |
|---|---|---|---|
| Unit 3 Stack | 33 | 126,000 (16) | 170,000/179,000 (22) |

The hours are based on 70% ACF/85% operating factor (OF) to 2015 (where the OF is equal to the actual running hours at any load in a year divided by 8760) and 10% ACF/20% OF from 2015-2020. The hours for 2015 and 2020 would be about 16,000 hours less if plant runs closer to historical 40% ACF up to 2015.

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.7.3 Inspection and Repair History

The plant has been diligent in its inspections of the stack and has performed regular PM inspections and completed the suggested repairs.

Previous stack inspection reports indicate that there has been no major cracking or structural issues. There is some small cracking in portions of the stack and some water infiltration around construction joints. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. The condition of the current linings and cap seems to suggest that Unit 3 has not been operating below the sulphuric acid dew point. The recent change to a much lower sulphur fuel oil has also reduced the acid dew point temperature, thereby allowing the plant to operate at a lower stack exit temperature to improve efficiency.

The life of the steel liners will vary depending on the materials of construction, the flue gas constituents, and the flue gas exit temperature. The upper liner sections of the stack are made of stainless steel to address the higher likelihood of acid attack as the flue gas cools going up the stack to levels approaching the acid dew point (local cooling could be below the dew point). The lower section of the liner is carbon steel which is adequate, provided the temperature in that zone does not frequently fall below the acid dew point of the stack. The design life of the liners should have been at least 30 years for the design fuels and operating conditions.

The inspections also suggest that life should not be an issue for the liner for the next ten years, despite the fact that portions of the liner are in excess of 33 years of age. The Unit 3 stack has seen approximately 16 years of operation over the period and therefore should be in reasonable shape. An additional 6 to 8 years of equivalent operation life may require some more careful examination. It is suggested that during the next stack inspection, NDE thickness measurements be taken at strategic points on both the stainless steel and carbon steel liners.

The stack breeching is designed to connect the ductwork into the liner of the stack. Currently it is the primary issue. The insulated steel lined duct stack breeching was replaced in 1990 with an internal refractory brick insulated duct. This was unsuccessful due to an adhesive membrane failure which caused the refractory to fall off and resulted in duct corrosion. Due to the unreliability and cost of the refractory brick lined duct, it is planned to refurbish it with an exterior insulated steel duct.

The stacks and the stack breeching (after being upgraded) are expected to make the 2020 generation end date.

### 10.2.7.4 Condition Assessment

The condition assessment of the Unit 3 stacks and breeching is illustrated below in Table 10-57.

**TABLE 10-57 CONDITION ASSESSMENT – UNIT 3 STACKS AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 105 | 17 | The concrete stacks are in good condition. The carbon steel portions of the liners have localized areas of heavy corrosion as well as areas with minimal corrosion. Carbon steel liner was replaced in 2001. | 3a | (60/30) | 30 | 2041 | 2012 | 2012 | Yes | Yes | 1980 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 271682 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 106 | 17 | Installed in 1990 , the current refractory brick lining in the breeching is cracked, causing local corrosion. It is planned to refurbish the ducting and replace the refractory brick with and insulated steel lined duct. | 10 | (30) | 2 | 2020 | 2012 | 2012 | Yes | No | 1990/2013 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.
3. The ability of the stack breeching to meet the EOL date of 2020 will be affected if planned refurbishments in 2013 are not undertaken.
4. The stack end of life is identified as 2041, assuming that it would not be demolished before the plant itself is closed.

### 10.2.7.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 stacks and breeching:

**TABLE 10-58 RECOMMENDED ACTIONS – UNIT 3 STACKS AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8437 | 8448 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 150 | 17 | Paint stack, at least top portions, within next five years. | 2013 | 1 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 151 | 17 | Continue current stack inspections every 3 years and monitor degradation of concrete stacks and steel liners. | 2013 | 1 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 152 | 17 | Continue to make repairs to deficiencies found in inspection reports. | 2013 | 1 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 153 | 17 | Undertake planned stack breeching repairs, including patching steel liner, installing external insulation, refurbishing corroded support structure, and providing ice protection shelter. | 2013 | 1 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 154 | 17 | Re-assess need to replace carbon steel lining. | 2013 | 1 |

### 10.2.7.6 Risk Assessment

The risk assessment associated with the Unit 3 stacks and breeching, both from a technological perspective and a safety perspective, is illustrated below in Table 10-59

**TABLE 10-59 RISK ASSESSMENT – UNIT 3 STACKS AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #3 Concrete Shell | 132 | 17 | Structural cracking. | 30 | None | 1 | D | Medium | 1 | D | Medium | Structural failure requiring shutdown, unit outage. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #3 Stainless Steel Liner | 133 | 17 | Corrosion/failure. | 10 | None | 1 | B | Low | 1 | C | Low | Corrosion causing major leak or failure – major leak requiring repair and unit outage. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | Unit #3 Carbon Steel Liner | 134 | 17 | Corrosion/failure. | 10 | None | 3 | B | Medium | 3 | C | Medium | Corrosion causing major leak or failure – major leak requiring repair and unit outage. | Current inspection and maintain. |
| 1296 | 8193 | 8336 | 8437 | 8448 | 271682 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | Unit #3 Stack Breeching | 135 | 17 | Corrosion/failure. | 2 | None | 1 | D | High | 3 | C | Medium | Corrosion causing major leak or failure – major leak requiring repair and unit outage. | Repair and maintain. |

### 10.2.7.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 stack and breeching system is illustrated below. Two curves represent the stack, the stack breeching, and the stack liners based on their in-service dates. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Several risk areas reflect also the differing normal lives of the components. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

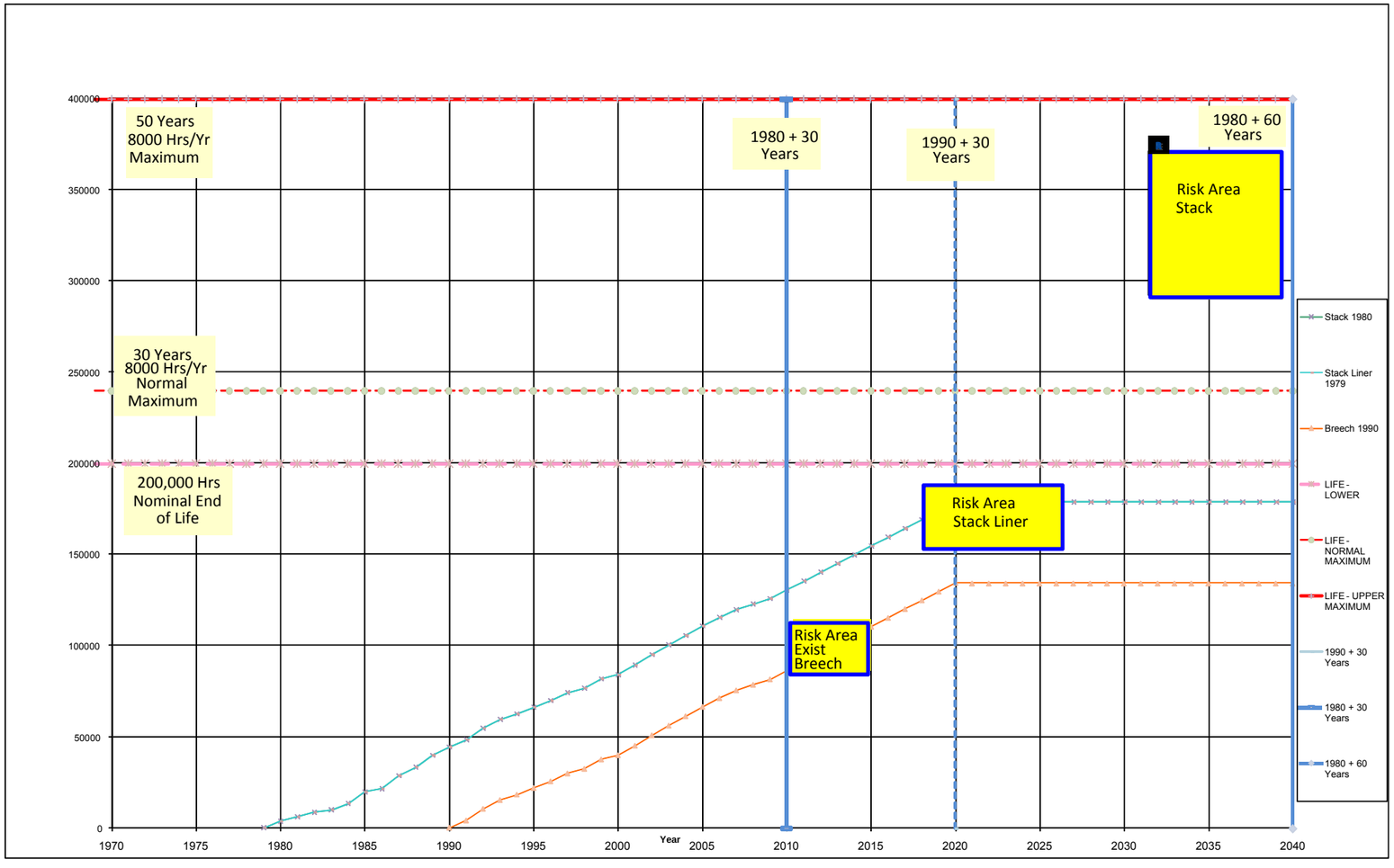



**FIGURE 10-23 LIFE CYCLE CURVE – UNIT 3 STACKS AND BREECHING**

The curves indicate that the remaining life (RL) of the Unit 3 stack is able to reach the desired life (DL) 2020 end date for generation, as well as the end date of 2041 for synchronous condensing/plant life. It does show that the stack breeching is in need of immediate repair. The breeching requirement is not a normal life issue, but one of design. Other elements can achieve the 2020 end date for generation with the ongoing plant maintenance program.

### 10.2.7.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-60 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-60 LEVEL 2 INSPECTION – UNIT 3 STACKS AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | None | 113 | 17 | No Level 2 inspections required. Continue inspections every 3 years and monitor degradation of concrete stacks and steel liners. | | | |
| 1296 | 8193 | 8336 | 8437 | 8448 | 271682 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | None | 114 | 17 | No Level 2 inspections or testing is required (based on breeching refurbishment as planned). | | | |

### 10.2.7.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 stacks and breeching include:

**TABLE 10-61 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 STACKS AND BREECHING**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 99 | 17 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8437 | 8448 | 0 | 3 | BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK | N/A | 100 | 17 | 3 | No capital required. | | |
| 1296 | 8193 | 8336 | 8437 | 8448 | 271682 | 3 | BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | N/A | 101 | 17 | 3 | Refurbish stack breeching. | 2014 | 1 |

### 10.2.8 Asset 8712 – Unit 3 Electrical and Control Systems (including DCS) Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 6)

The assets listed below include only those identified as exclusive to the plant steam systems.

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 – Assets Generation |
| SCI & System: | 3712 #3 Electrical Systems & Control |
| Sub-Systems: | 3712 #3 Electrical Systems & Control |
| Components: | 8699 #3 Burner Management<br>309901 #3 Boiler Protection and Control<br>8238 #3 Turbine Governor System |

#### 10.2.8.1 Description

The following information covers the Unit 3 electrical and control systems with the plant and its associated buildings:

**Asset 8238 Unit 3 Turbine Governor System**

The turbine governor system is mechanical fly-ball type system manufactured by Hitachi, and installed in 1979. Speed control is via linkages and dashpots. Monitoring of the governor is by the Bently Nevada system which provides vibration monitoring, differential protection, etc. Load limit control is an ongoing problem, which appears "course" at times. However, there is ongoing discussion between the plant and GE as to the root cause and eventual rectification of this problem. Control (Instrument) involvement with the governor is limited to the monitoring of valve positions, speed load, and load limit control points. All outputs are into the DCS and are monitored in the control room.

**Asset 8699 Unit 3 Burner Management**

The burner management system is a Foxboro (DCS) system, which was changed over in 2007. The soot-blower control system was installed in approximately 1980. It contains control relaying, motor starters and overloads, etc. The control relaying was replaced, in 2003 with an Omron SYSMAC C200HS PLC, with PS221 controllers and I/O modules. The starters are original CGE type CR205APO, with Allen Bradley type 810-!04 AB dashpot overloads. Field junction boxes are not very accessible. The igniter relay marshalling cabinets have some issues but they are not excessive.

**Asset 301711 Unit 3 DCS**

The DCS, manufactured by Foxboro, is an Invensys system that was installed in 2004. New cabling and Westinghouse panels housing the DCS were installed in the late 1990's. The original system was hard-wired but later upgraded to a Westinghouse system. Westinghouse could not support the system which was then updated to Foxboro in 2004.

**Asset 309901 Unit 3 Boiler Protection and Control**

The boiler protection and control system provides safety of personnel, protection of the boiler and its equipment, and control of the boiler processes. In 2004, the system was upgraded to the present Foxboro DCS system and control algorithms again were revisited. The Foxboro DCS equipment was mounted within the original Westinghouse WDPF enclosures.

### 10.2.8.2 History

The requirements for the electrical and control systems associated with the steam system for Holyrood are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Controls Upgrade | 2004 |

### 10.2.8.3 Inspection and Repair History

Foxboro technical support is provided a number of times per year under a service contract and upgrades are completed as required. Field adjustments and modifications will continue as necessary.

### 10.2.8.4 Condition Assessment

The condition assessment of the Unit 3 electrical and control system (including DCS) associated with steam systems is illustrated below in Table 10-62.

**TABLE 10-62 CONDITION ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION&CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 182 | 6 | Generator & Transformer & Auxiliary Protection and Metering Panels tests were satisfactory (2007). Some ingress of dust and foreign material. Testing is on a 6 year cycle (2013, 2019, 2025, etc.). | 10 | (30) | 10+ | 2020 | 2013 | | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 183 | 6 | Installed in 1980. Protection, synch, and control relays are original electro-mechanical. Feeders Motor Protection Relays installed in 2009. All overhauled in 2007-2009 OK except corrective actions on CWW3 Jan, 2010. (status 80). and UAT-3 breaker, no date but status 90. Transformers UAT3 and SAT34 in 2007 showed reasonable tolerances. All 600V swtchgear is | 10 | (30) | 10 | 2020 | 2007 | | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 0 | 3 | U3 GENERATOR | TURBINE GOVERNOR | TURBINE GOVERNOR SYSTEM | N/A | 184 | 18 | "Course" load limit control is an ongoing problem. Control (Instrument) involvement of DCS limited to the monitoring of valve positions, speed load and load limit control points. | 4 | 200000 (30) | 5 | 2020 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8712 | 271767 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 185 | 6 | Operating well, with numerous spares. In 2010 will progress toward Phase 5 (Obsolescence) status at some indeterminate time. | 10 | (20) | (5) | 2020 | | | No | No | 2004 |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 186 | 6 | Generator, turbine and boiler controls linked to the DCS with some original controls, indications and annunciations replaced. ASEA cabinets behind control room in hazardous state, with cabling so congested as to render the doors in the vertical sections unable to be closed. Potential for major failure and unit out of service for an indeterminate time. | 4 | (30) | 2 | 2020 | | | Yes | No | 1980/2007 |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 187 | 6 | Installed in 2004 - state of the art. | 3a | (20) | 20 | 2041 | | | Yes | Yes | 1980/2004 |
| 1296 | 8193 | 8712 | 309896 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | 600 V MELTRIC PLUGS | 600 V MELTRIC PLUGS | N/A | 188 | 6 | New system. | 3a | (50) | 30 | 2041 | | | No | No | 2007 |
| 1296 | 8193 | 8712 | 8699 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 189 | 6 | Foxboro (DCS) system in 2007. Soot-blower controls from 1980, with control relaying replaced in 2003. Igniter relay marshalling cabinets have some troubles but not excessive. | 4 | (25) | 10 | 2020 | | | Yes | Yes | 2007 |
| 1296 | 8193 | 8712 | 309901 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 190 | 6 | In 2004, the system was updated to the Foxboro DCS system in the original WDPF enclosures. | 3a | (20) | 15+ | 2020 | | | Yes | Yes | 2004 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.8.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 electrical and control systems (including DCS) associated with steam systems:

**TABLE 10-63 RECOMMENDED ACTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | N/A | 266 | 6 | See details below. | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 267 | 6 | Test Generator G3, Transformer T3 and Auxiliaries P&C Panels - next tests planned for 2013 2019, 2025, etc. | 2011 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 268 | 6 | Include this Switchgear, 4160V/600V relaying in SB2 modernization study (5.3.2.28 IV) for the protection relays. | 2014 | 1 |
| 1296 | 8193 | 8712 | 8704 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 269 | 6 | Carry out the NLH capital budget item to "Upgrade Unit 3 Relay Panels" in 2011, to provide a safe system and discard the existing cabinets and their contents, and redirect the existing field cables to the DCS system for Unit 3. Investigations will need to be conducted at site, and discussions held with Foxboro to determine if the present DCS physical size can accommodate the changes, or if it will need to be extended. | 2011 | 2 |
| 1296 | 8193 | 8712 | 301711 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 270 | 6 | Maintain DCS system current through existing Foxboro replacement service agreement. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271767 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 271 | 6 | Assess Turbine Supervisory System replacement options (vendor, GE 3500 Series Monitoring System, other GE options) that might be available in 2010-2011. | 2011 | 1 |
| 1296 | 8193 | 8712 | 8699 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 272 | 6 | No action is required. | 2011 | 2 |
| 1296 | 8193 | 8712 | 309901 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 273 | 6 | No recommended action. | | |

### 10.2.8.6 Risk Assessment

The risk assessment associated with the Unit 3 electrical and control system (including DCS) associated with steam systems, both from a technological perspective and a safety perspective, is illustrated below in Table 10-64.

**TABLE 10-64 RISK ASSESSMENT – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION&CONTROL | N/A | 226 | 6 | Electrical fault, mechanical fault, ops error. | 5+ | None | 2 | C-D | Medium | 2 | C-D | Medium | Loss 1 unit generation, damage to unit or equipment. | Current inspection and maintain. |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 227 | 6 | Electrical fault, mechanical fault, ops error. | (5) | None | 3 | B-C | Medium | 3 | B-C | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 228 | 6 | Electrical fault, mechanical fault, ops error. | 2 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Current inspection and maintain. |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 229 | 6 | Electrical fault, ops error. | 20 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Maintain. |
| 1296 | 8193 | 8712 | 271767 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TURBINE SUPERVISORY SYSTEM (TSI) | TURBINE SUPERVISORY SYSTEM | N/A | 230 | 6 | Electrical fault, mechanical fault, ops error. | (5) | None | 3 | C | Medium | 3 | C | Medium | Loss 1 unit generation. Damage to unit. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 8699 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 231 | 6 | Electrical fault, mechanical fault, ops error. | 10+ | None | 3,1 | C | Medium/ Low | 1 | C | Low | Loss 1 unit generation. Equipment damage. | Refurbish or replace. |
| 1296 | 8193 | 8712 | 309901 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 232 | 6 | Electrical fault, mechanical fault, ops error. | 15+ | None | 1 | 2 | Low | 1 | B | Low | Loss of part of 1 unit generation. Equipment damage. | Maintain. |

### 10.2.8.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 electrical and control systems (including DCS) associated with steam systems is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

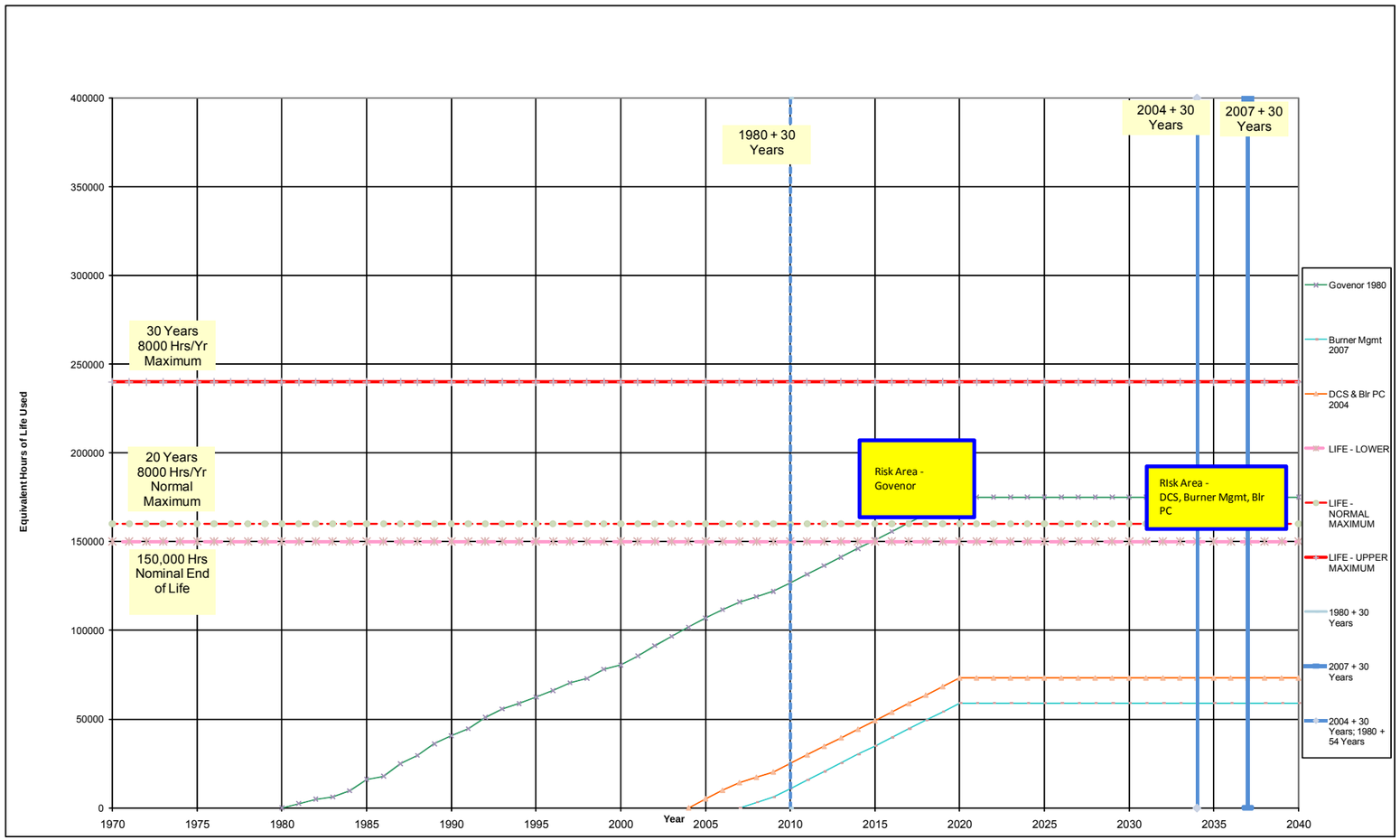



**FIGURE 10-24 LIFE CYCLE CURVE – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 3 control systems (including DCS) associated with steam systems can readily reach the desired life (DL) 2020 end date for generation, provided regular inspection and service per the station PM plan is maintained. The electrical systems, particularly breakers and motor controls are addressed in more detail as part of Section 10.1.3. It is clear that in order to meet the end date for generation service, some of these components must be replaced or in some cases refurbished.

### 10.2.8.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-65 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-65 LEVEL 2 INSPECTIONS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | None | 209 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | None | 210 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | None | 211 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8716 | 8724 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UNIT SERVICE POWER SYSTEM | BOILER AREA BAB-3 | None | 212 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | None | 213 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | None | 214 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 271767 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | None | 215 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 8699 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BURNER MANAGEMENT | BURNER MANAGEMENT | None | 216 | 6 | No Level 2 inspections or testing is required. | | | |
| 1296 | 8193 | 8712 | 309901 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | None | 217 | 6 | No Level 2 inspections or testing is required. | | | |

### 10.2.8.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 electrical and control systems (including DCS) associated with steam systems include:

**TABLE 10-66 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 ELECTRICAL AND CONTROL SYSTEMS (INCLUDING DCS) ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8712 | 0 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | ELECTRICAL SYSTEM & CONTROL | N/A | 187 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 188 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | N/A | 189 | 6 | 3 | Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | N/A | 190 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 271767 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TURBINE SUPERVISORY SYSTEM (TSI) | TSI | N/A | 191 | 6 | 3 | Replace with selected preferred option. | 2013 | 1 |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | N/A | 192 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 301711 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | DISTRIBUTED CONTROL SYSTEM (DCS) | DCS | N/A | 193 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 309896 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | 600 V MELTRIC PLUGS | 601 V MELTRIC PLUGS | N/A | 194 | 6 | | No capital required. | | |
| 1296 | 8193 | 8712 | 8699 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BURNER MANAGEMENT | BURNER MANAGEMENT | N/A | 195 | 6 | 3 | No capital required. | | |
| 1296 | 8193 | 8712 | 309901 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BOILER PROTECTION & CONTROL | BOILER PROTECTION & CONTROL | N/A | 196 | 6 | 3 | No capital required. | | |

### 10.2.9 Asset 271675 – Unit 3 Steam Turbine

(Detailed Technical Assessment in Working Papers, Appendix 18)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generation |
| SCI & System: | 8194 #3 Turbine & Generator |
| Sub-Systems: | 271675 #3 Steam Turbine |
| Components: | 8196 #3 Main Steam Chest |
| | 8201 #3 HP Turbine |
| | 8211 #3 IP Turbine |
| | 8217 #3 LP Turbine |
| | 8230 #3 Front Standard |

Note: High energy piping and hangers are addressed within the Boiler Section (Section 10.2.1) under heading Boiler Main Steam Lines (Asset Code 8372). The scope is assumed to include piping and hangers up to the steam turbine.

#### 10.2.9.1 Description

The Unit 3 150 MW model D5 Hitachi turbine was supplied in 1979. The turbine is rated to operate at the main steam inlet pressure of 13 MPag (1890 psig) and steam temperature of 538 °C (1,000 °F). The reheat steam inlet temperature is 538 °C (1,000 °F). The turbine shaft speed is 3,600 RPM.

The unit consists of one combined high pressure (HP) and intermediate (IP) turbine and one double flow LP turbine. The HP/IP and LP rotors are integral with the blade wheels. There is no centerline bore through the rotors. The turbine rotors are supported by four journal bearings. The trust bearing is located between the IP and LP turbines. The turning gear is located between the LP turbine and the generator.

The generator rotor is directly-coupled to the turbine. It is supported by two journal bearings located in the stator end-shields.

The Unit 3 steam turbine has a hydraulic control system that uses the same lube oil as the turbine bearings. The unit is partial arc machine with 4 control valves.

The unit has two main stop valves (MSVs). One of the MSVs has an internal pilot valve to control the turbine run up to full speed. There are two combined casing reheat stop and intercept valves.

The steam seal regulator (SSR) is the key component of the steam turbine gland steam sealing system. The SSR controls the flow of steam to and from all of the turbine shaft seals. The seals minimize the leakage of process steam along the rotor shaft from the turbine casing. There SSR must be able to respond differently at low and high loads.

The turbine auxiliaries included in this report are:

- The lube oil system
- The hydraulic control oil system, ;
- The gland steam sealing system, including steam seal regulator;
- The emergency blow down valve; and
- The power assisted extraction steam non return valves (NRVs).

#### 10.2.9.2 History

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Unit 3 IP 1st Stage Blades | 2007 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Last Major Overhaul | 2007 |
| Last Valve (Minor) Overhaul | 2004 |
| Next Major Overhaul/Inspection | 2016 |
| Next Valve (Minor) Overhaul | 2010/2013 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

#### 10.2.9.3 Inspection and Repair History

The turbine major overhauls have been completed on a six year frequency. As of the year 2007, the overhauls are scheduled to be done every 9 years with the next overall scheduled for the year 2016. The turbine valve overhaul that is on 3 year frequency remains unchanged. The last valve overhaul was completed in the year 2007. The next overhauls are scheduled for years 2010 and 2013.

The reports indicate the overhaul work has been done by General Electric (GE) since the year 2001.

Over speed testing is completed once a year prior to the unit seasonal shut down and after every valve or turbine major overhaul.

The original SSR was an automated hydraulic system that contained many moving parts and wear points requiring manual intervention etc. In 2009, the existing SSR was replaced by a pneumatically operated pressure control valve system in order to improve the system reliability.

**2001 Major Turbine & Valve Overhaul**

Sometimes prior to the outage, a turbine water induction (TWI) incident likely (plant indicated otherwise) took place on this unit where the cold saturated steam flowed to the hot IP turbine from the boiler reheater section. The date of the incident or number of incidents is not known. A cold quenching steam flow through a turbine is considered a TWI incident per the ASME guideline. The damage to the turbine rotor, casings, steam path components etc. will depend on the duration, temperature differential, and the flow rate of the cold steam. The TWI can cause the inner and outer casings to distort and crack, shaft to bow, and excessive shaft vibrations that would damage the steam path components. The damage reported below (HP/IP outer casing distortion, excessive integral root and spill strips damage, cracks in the steam chest, etc.) are caused by TWI:

- The HP nozzle partition plates had cracks. These were removed and site weld repaired using inconel wire. GE recommended these be inspected and repaired off site during the next outage.
- HP/IP outer upper casings had cracks. These were ground out and not weld repaired. The depth ground out was about 3/8 inch. The lower inner casing was not removed and therefore the lower outer casing could not be inspected. GE recommended that the lower inner casing be removed during the next outage and both the inner and outer casing be inspected for cracks.
- The HP/IP outer casing horizontal joint has significant distortion in the mid section. GE recommended that the distortion be monitored for change during the next outage. Note that the cold RH steam was admitted in the mid section of the HP/IP casing and would come into direct contact with the casing which resulted in distortion.
- Most HP spill strips were damaged. They were straightened and dressed.
- The 7th IP stage (1st reheat) diaphragm was repaired off site. A protective coating was not reapplied.
- The IP 8th, 9th and 10th stage diaphragms partitions were damaged. They were dressed and weld repaired on site. The 11th and 12th stage diaphragms have cracks in the half joint. These were removed and weld repaired.
- Most IP diaphragms root radial seals and the tip spill strip seals were badly damaged. Some were weld repaired, straightened and dressed up. GE recommended that all IP diaphragms be sent off site during the next outage for major repair.
- Most shaft and gland packing were damaged. No spares were available. The packing seals were chased and sharpened.
- Some LP turbine diaphragm partition plates in both flows had cracks and were weld repaired.
- Cracks in the struts welds of the LP inner upper and lower casings were weld repaired.
- The LP inner half casing joints had groove cutting due to water erosion. Both top and bottom joint surfaces were weld repaired, grinded and stone levelled.
- The upper steam chest snout rings were replaced per GE new style locking rings. GE recommended that during the next outage, the lower snout rings must be replaced.
- The stems of both MSVs were replaced due to excessive run out.
- Serviced all lube oil pumps. Cleaned the oil tank and the coolers. The lube oil system was flushed.
- Steam seal regulator broken stem was replaced.

On startup, the turbine shaft vibrations were high. For unknown reasons, the balance weights installed during the year 1994 were removed and had to be reinstalled.

There is no mention in the report if ultrasonic testing (UT) was completed on the lower steam chest. Turbine Consults Inc. recommended that UT be completed to monitor the crack growth rate. The last UT inspections were done in years 1999 and 2000.

The cracks in the lower steam chest and the distortion in the mid section of the HP/IP outer casing are connected to the TWI incident.

**2004 Turbine Valve Overhaul**

- The UT inspection of the lower steam chest indicated that the crack found in 1998 had not grown since the 1999 UT inspection. The report also referred to a weld repair in 2001 (a pad of weld added to the outside of the area where the crack was found). No details were provided in the 2001 report.
- The upper steam chest was inspected using liquid dye penetrant (red dye). No cracks were found.

- Balance weights were added to the journal bearing #1 and #2 ends. The vibrations levels at bearing #1 were high during the past operating season cycle.
- The stems of both MSVs were replaced due to excessive run out.

The report did not specify if the full flow in-line filter cubical was hooked up to the lube oil system during this outage or earlier during the 2002 outage.

**2007 Turbine Major Overhaul**

- The follow up UT inspection on the lower steam chest indicated that the crack found in 1998 had not grown since the 1999 UT inspection. However, the NDE Company that did the UT is not confident with the crack size depth estimation.
- The upper steam chest was inspected using red dye. No cracks were found.
- The distortion in the mid section of the HP/IP outer casing horizontal joint was checked. There was no change (see 2002 overhaul summary above).
- The HP nozzle partition plates #1 and #14 had erosion notching and thinning. Both were TIG inconel weld repaired at site.
- The HP stage 2 diaphragm was shipped to off site for a major weld repair and a correction of the pitch to throat ratio. The spill strips were replaced.
- The HP stage 3 diaphragm had three cracks in the partition. It is not clear if these were weld repaired.
- The spill strip seal of the HP diaphragm stages 3 to 6 were damaged and were not replaced or repaired
- The IP first stage blades were replace and coated with GE diamond Tuff coating to protect the blades against solid particle erosion (SPE). The rotor dovetails were inspected and no cracks were found.
- The IP first stage diaphragm was sent off site for major partition repairs using 410 SS weld filler metal. The root radial integral seal was restored. The caulking groove was repaired and new tip spill strips were installed. After repair, the diaphragm was coated with GE diamond Tuff coating.
- The IP 8th stage diaphragm was sent off site for major partition repairs. The old inconel weld was removed and a new 410 SS weld repair was done. The root radial integral seal was restored. The caulking groove was repaired and new tip spill strips were installed.
- The IP 9th stage diaphragm partitions were refurbished and polished. The root radial and tip spill strip seals were not replaced or repaired.
- The IP 10th stage diaphragm was sent off site for major partition 410 SS weld repair and the correction of the pitch to throat ratio.
- The LP both flow diaphragms #13 and #14 were inconel weld repaired, "benching back", cold straightened and the surfaces polished where required. The 14th stage spill strip seals were replaced.
- The 18th stage generator end diaphragm partition #1 had some inconel repairs and cold straightening.
- The Lo blades had extensive water erosion in the last 10 cm (4 inches) of the blade height. The trailing edges are worn with deep sharp edges near the tip. There is also water erosion in the base metal ahead of the stellite bar nose. GE had a concern that the sharp edges could turn into cracks. No repair work was done.
- GE recommended that the Lo blades be repaired during the next outage.
- Finger dovetail pins were broken on two Lo blades and were replaced.
- All control valve (CV) main camshaft bearings and bushes were found defective or worn. They were replaced.

- All four CV snout rings were replaced by the new GE style locking rings.
- Stems of both Main Stop Valves (MSV)s were replaced due to an excessive run out.
- The stem of right side Reheat Stop Valves (RSV) was replaced due to an excessive run out.
- Stems of both Intercept Vales (IV) had to be cut to allow valve disassembly.
- A crack was repaired in the weld joint between the mesh and the strainer body of the left hand RSV. The weld repair was performed as per a GE approved procedure.
- Bearings No.'s 2, 3 and 5 were replaced due to poor bonding of the Babbitt linings. Bearing No. 4 was replaced as it was partially wiped.
- Serviced all lube oil pumps. Cleaned the oil tank and the coolers.
- Both turbine rotors were low speed balanced on site.

### 10.2.9.4 Condition Assessment

The condition assessment of the Unit 3 steam turbine is illustrated below in Table 10-67.

**TABLE 10-67 CONDITION ASSESSMENT – UNIT 3 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | N/A | 30 | 18 | See detail below | 4 | 200000 (30) | 10 | 2020 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 31 | 18 | Large cracks in the weld joint between the lower steam chest and the outer casing - first seen in 1998 and are on the inside surface. No weld repair work has been done. Per the inspections, the cracks are not growing, but the NDE Company that did the UT in 2007 is not confident with the cracks size estimation. distortion of the HIP outer casing half joint at the mid section. | 4 | 200000 (30) | (3) | 2020 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 32 | 18 | Some minor SPE in the HP steam path components - repaired in 2007. Turbine is fairly good condition. The turbine valves and auxiliaries are in good condition. | 4 | 200000 (30) | 10 | 2020 | | 2016 | Yes | Yes | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 33 | 18 | The turbine valves and auxiliaries are in good condition. | 4 | 200000 (30) | 10 | 2020 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | N/A | 34 | 18 | Turbine is fairly good condition. Substantial SPE in IP steam path components. First stage blades replaced in 2007. First stage diaphragm had a major partition repairs. New blades and diaphragm coated with a diamond tuff coating to protect the blades against future SPE damage. | 4 | 200000 (30) | 10 | 2020 | | 2016 | Yes | Yes | 1980/2007 |
| 1296 | 8193 | 8194 | 271675 | 8217 | 0 | 3 | U3 GENERATOR | TURBINE | L.P. TURBINE | N/A | 35 | 18 | Turbine is fairly good condition. The Lo blades have extensive water erosion in the last 4 inches of the blade height. Trailing edges worn with deep sharp edges near the tip. There is also water erosion in the base metal ahead of the stellite bar nose. | 4 | 200000 (30) | 6 | 2020 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8230 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 36 | 18 | High temperature studs and valves are original equipment. Generally valves in good shape. | 4 | 200000 (30) | 10 | 2020 | 2013 | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 99024410 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVISORY | N/A | 37 | 18 | See TSI | 4 | (25) | 5 | 2020 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 38 | 18 | Original equipment. No issues identified except steam seal regulator (below) | 4 | (30) | 10 | 2020 | | 2016 | Yes | Yes | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal Regulator | 39 | 18 | Original equipment. The Steam seal regulator 's many moving parts and wear points result in frequent binding and sticking requiring manual intervention. Parts are very difficult to obtain and the system should be considered obsolete. Failure to address could result in premature deterioration of the steam turbine generator bearings. | 10 | (30) | 2 | 2020 | | 2013 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8248 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 40 | 18 | Original equipment. Good condition. Not reviewed. | 4 | (30) | 10 | 2020 | | 2016 | Yes | No | 1980 |
| 1296 | 8193 | 8194 | 271675 | 8250 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 41 | 18 | Original equipment. Good condition. Not reviewed. | 4 | (30) | 10 | 2020 | 2013 | 2013 | Yes | No | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.
3. The ability of the steam seal regulator (SSR) to meet its next overhaul date and the EOL date of 2020 is conditional on its replacement as planned in 2013

### 10.2.9.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 steam turbine:

**TABLE 10-68 RECOMMENDED ACTIONS – UNIT 3 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | N/A | 54 | 18 | Maintain records on stud replacements - why, date and location. Mark all high temperature studs and install at the same location during every stud change out. | 2010 | 1 |
| 1296 | 8193 | 8194 | 271675 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | N/A | 55 | 18 | Increase Extraction steam NRV inspection from 3 years to 6 years. Top heater NRV need not be checked as there is no danger of over speed damage if the valve does not function. Check pneumatic actuator every 3 years. Ensure dry air is supplied to the cylinders. Check NRV valve operation on the seasonal restart every year. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 56 | 18 | Do phase array inspection of the cracks in the lower steam chest root area of the weld that joins the steam chest to the HIP outer casing. The 2010 bench mark PAI should be compared with the next phase array inspection in 2013 to establish if the crack is active and growing. | 2010 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 57 | 18 | Perform during every valve outage a boroscope inspection of the first stage nozzle for wear and tear and FOD/SPE damage. Take pictures for record. | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 58 | 18 | Have Hitachi identify casing studs close to the nozzle block studs that operate above 850○F prior to Unit 2016 overhaul that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement and estimate the remaining creep life of the studs. Since the turbine valves are opened more often and operated at 1000oF, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage. | 2014 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 59 | 18 | Inspect and record (take pictures) of the SPE/FOD damage to the HP and IP blades and the diaphragms. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 60 | 18 | Check the past 410 SS and inconel repairs in all HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and inconel repairs. Repair and dress damage where required. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 61 | 18 | Recheck the HP Stage 3 partitions and repair. During the 2016 Major Overhaul - per the 2007 report (page 68), there were three cracks in the HP stage 3 lower half diaphragm where the partitions entered the inner sidewall. The cracks may not have been repaired. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 62 | 18 | Have Hitachi identify studs that operate close to or above 850 °F that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement. Estimate the remaining creep life of the studs and replace studs close to the end of their life creep life | 2014 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8206 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 63 | 18 | Have Hitachi identify casing studs close to the nozzle block studs that operate above 850 °F prior to Unit 2016 overhaul that may have reached or are close to the end of their predicted creep life. Have Hitachi supply their engineering recommendations on the high temperature stud replacement and estimate the remaining creep life of the studs. Since the turbine valves are opened more often and operated at 1000 °F, their operating creep life will be shorter. They are also more liable to be damaged and are subjected to wear and tear during the valve 3 year disassemble. Replace all if the other majority of the studs in a valve body are being replaced due to mechanical, wear or tear damage. | 2014 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | N/A | 64 | 18 | Check the past 410 SS and inconel repairs in all HP and IP diaphragms. Record and compare the condition of wear of the 410 SS and inconel repairs. Repair and dress damage where required. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | N/A | 65 | 18 | Have Hitachi identify studs that operate close to or above 850 °F that may have reached or are close to the end of their predicted creep life. Hitachi supply their engineering recommendations on the high temperature stud replacement. Estimate the remaining creep life of the studs and replace studs close to the end of their life creep life. | 2014 | 1 |

Table 10-68 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 8217 | 3 | U3 GENERATOR | TURBINE | L.P. TURBINE | N/A | 66 | 18 | During the 2016 Major Overhaul:<br>- Where possible, inspection L0 and L-1 blade root and wheel steeple surfaces.<br>- Inspect L0 blades for water erosion near the tips and report. Take pictures of the blade surfaces with water wear.<br>Per GE recommendation, have a plan ready to weld repair the blades if necessary. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8217 | 3 | U3 GENERATOR | TURBINE | L.P. TURBINE | N/A | 67 | 18 | If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door. This should be done after the unit is shut down after every seasonal operation. | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8230 | 3 | U3 GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 68 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 3 | U3 GENERATOR | TURBINE | TURBINE GOVERNOR SYSTEM | N/A | 69 | 6 | Upgrade the mechanical fly-ball type turbine governor system to as-built condition or be replaced. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVISORY SYSTEM | N/A | 70 | 6 | Assess and replace turbine supervisory system. | 2012 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8244 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 71 | 18 | Replace seal seal regulator in 2013. Undertake other normal major overhaul work. | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8248 | 3 | U3 GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 72 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8250 | 3 | U3 GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 73 | 18 | No specific recommended actions, beyond normal major overhaul work. | 2016 | 1 |

### 10.2.9.6 Risk Assessment

The risk assessment associated with the Unit 3 steam turbine, both from a technological perspective and a safety perspective, is illustrated below in Table 10-69

**TABLE 10-69 RISK ASSESSMENT – UNIT 3 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | | 40 | | See detail below. | 10 | | | | | | | | | |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 41 | | Cracks in lower steam chest and casing. Valve mechanical failure. | (1) | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure. | Inspect and maintain. Identify long term solution. |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | HP TURBINE | High pressure turbine diaphragms, nozzle partition plates and turbine blades. | 42 | 18 | Mechanical failure - relative higher risk from erosion and Foreign Object Damage (FOD). | 10 | None | 2 | C | Medium | 2 | C | Medium | Turbine lost generation, efficiency, capacity. | Some repairs in 2007. Inspect and maintain. Eliminate FOD. |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE REHEAT/IP STEAM CHEST | | 43 | | Valve mechanical failure. | 10 | None | 2 | C | Medium | 2 | C | Medium | Turbine shutdown, overspeed failure. | Inspect and maintain. Identify long term solution. |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | IP TURBINE | Intermediate pressure turbine diaphragms, and first stage turbine blades. | 44 | 18 | Mechanical failure - SPE and erosion from foreign object damage (FOD). | 10 | None | 2 | C | Medium | 2 | C | Medium | Turbine lost generation, efficiency, capacity. | In 2007, the IP first stage blades replaced and the IP first stage diaphragm (and others) had a major partition repairs. New blades and diaphragm diamond tuff coated. Check condition of the first stage RH blades in 2016 overhaul. Eliminate SPE. |
| 1296 | 8193 | 8194 | 271675 | 8217 | 0 | 3 | U3 GENERATOR | TURBINE | LP TURBINE | Low pressure turbine | 45 | 18 | Chemical/mechanical failure - LP monoblock integral discs - SCC failure. | 10 | None | 1 | C | Low | 1 | C | Low | Turbine lost generation, efficiency, capacity. | Manage the condensate and feedwater chemistry within the ASME guidelines, |
| 1296 | 8193 | 8194 | 271675 | 8230 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE FRONT STANDARD | | 46 | | Not addressed. Mechanical failure. | 10 | None | 1 | C | Medium | 1 | C | Low | Turbine shutdown, overspeed failure. | Inspect and maintain. Identify long term solution. |
| 1296 | 8193 | 8194 | 271675 | 8236 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GOVERNOR SYSTEM | Turbine governor system | 47 | 6 | Electrical, mechanical failure, ops error. | 5 | None | 1 | C | Low | 1 | C | Low | Loss 1 unit generation. Damage to unit. | Current inspection and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8236 | 99024410 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVISORY SYSTEM | Turbine supervisory system | 48 | 6 | Electrical fault, mechanical fatigue, ops error. | 5 | None | 3 | C | Medium | 3 | C | Medium | Loss 1 unit generation. Damage to unit. | Refurbish or replace. |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 49 | | Not addressed. Mechanical sealing failure. | 10 | None | 1 | C | Low | 1 | C | Low | Steam leak. | Inspect and maintain. . |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Steam Seal regulator | 50 | 18 | Control failure/Parts obsolete | (4) | Essentially at EOL | 3 | C | Medium | 3 | C | Medium | Turbine shut down. Bearing failure. | Replace |
| 1296 | 8193 | 8194 | 271675 | 8248 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 51 | | Not addressed. | 10 | None | 2 | A | Low | 1 | A | Low | Slow start up. | Inspect and maintain. |
| 1296 | 8193 | 8194 | 271675 | 8250 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 52 | | Not addressed. Mechanical chain failure. | 10 | None | 3 | B | Medium | 3 | A | Low | Turbine bowing without turning - gear on shutdown. | Inspect and maintain. |

### 10.2.9.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 steam turbine is illustrated below. One curve indicates that the major elements of the turbine are original equipment. The unit is due to undergo a major overhaul in 2016. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

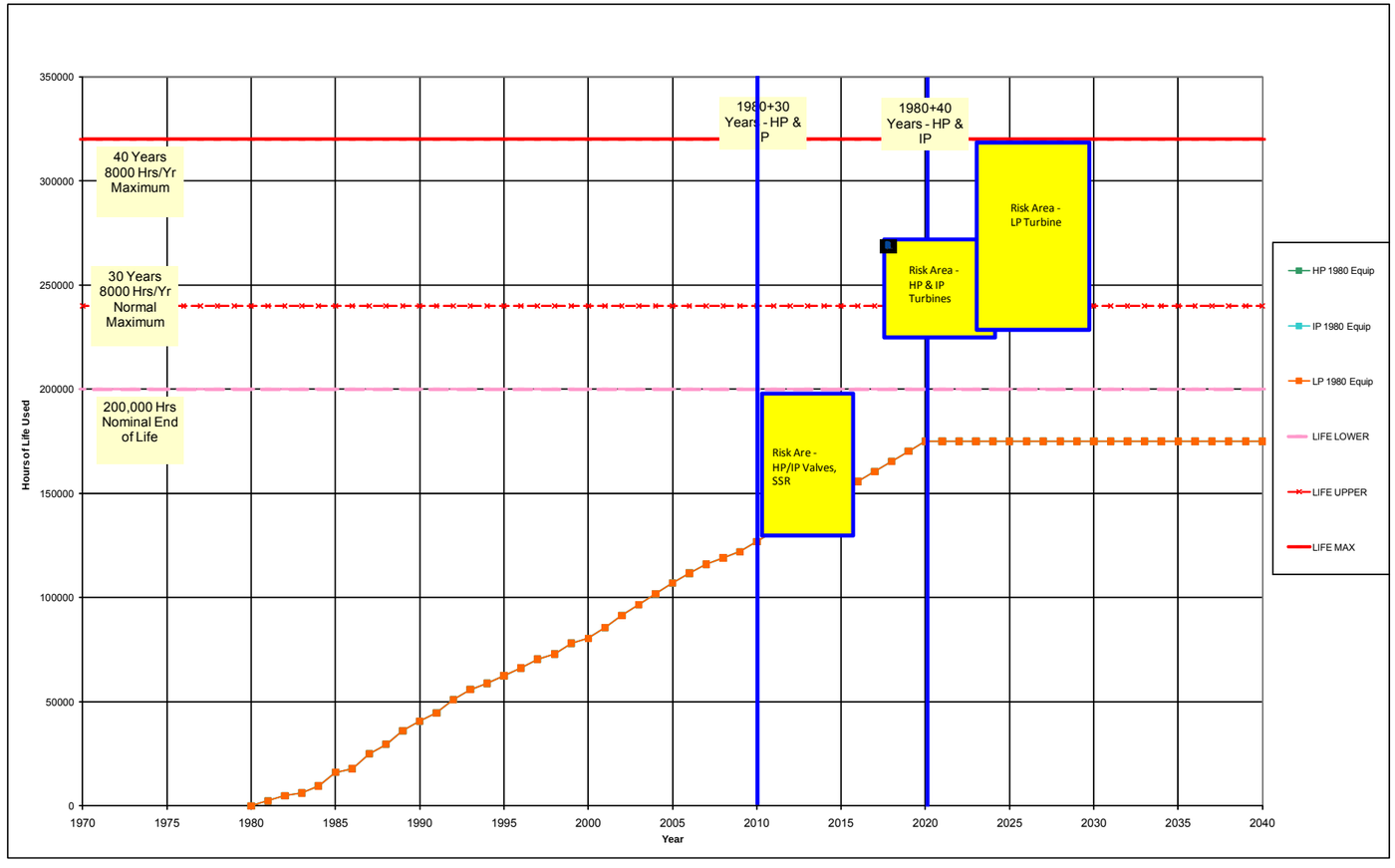



**FIGURE 10-25 LIFE CYCLE CURVE – UNIT 3 STEAM TURBINE**

The curves indicate that the remaining life (RL) of the various elements of the Unit 3 steam turbine exceeds the desired life (DL) which is the lesser of the time to its next major planned overhaul/inspection (2016) or to the desired End of Life (EOL) date of 2020. In fact the 2020 end date should be readily achievable. No specific dedicated Level 2 is required, but sufficient inspection and testing will be required in the 2016 overhaul to confirm the ability to meet the 2020 EOL date. The exception to this is the SSR and the high temperature stud bolts. It is clear that the current inspection schedule seems suitable.

### 10.2.9.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the Level 2 analyses recommended are presented in Table 10-70 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-70 LEVEL 2 INSPECTION – UNIT 3 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | None | 27 | 18 | Level 2 is essentially the Steam Turbine Overhaul | 2016 | 1 | $2,601 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | None | 28 | 18 | HP Steam Chest Phased Array Inspection (PAI) - In 2010, do the phase array inspection of the cracks in the lower steam chest root area of the weld that joins the steam chest to the HIP outer casing. The 2010 bench mark PAI should be compared with the next phase array inspection in 2013 to establish if the crack is active and growing. | 2010 | 1 | $22 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | None | 29 | 18 | First Stage Nozzle Borescope: During every valve outage, do a bore scope inspection of the first stage nozzle for wear and tear and FOD/SPE damage. Take pictures for record. | 2011 | 1 | $6 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | None | 30 | 18 | Identify and assess HP Inner Casing Studs prior to Unit 2016 overhaul NL Hydro should have Hitachi identify studs that operate close to and above 850 ○ F and have Hitachi supply their engineering recommendations on the high temperature stud replacement. | 2011 | 1 | $6 |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | None | 31 | 18 | Identify and asses studs that operate above 850 ○ F may have reached or are close to the end of their predicted creep life (CV/RSV and ICV studs) | 2011 | 1 | $6 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | None | 32 | 18 | Identify and assess IP Inner Casing Studs prior to Unit 2016 overhaul NL Hydro should have Hitachi identify studs that operate close to and above 850 ○ F and have Hitachi supply their engineering recommendations on the high temperature stud replacement. | 2011 | 1 | $6 |
| 1296 | 8193 | 8194 | 271675 | 8217 | 0 | 3 | U3 GENERATOR | TURBINE | L.P. TURBINE | None | 33 | 18 | LP L0 blades Boroscope: If possible, do bore scope inspection of LP L0 blades once a year through the LP turbine inspection door, done after the unit is shut down after every seasonal operation. | 2010 | 1 | |
| 1296 | 8193 | 8194 | 271675 | 8230 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE FRONT STANDARD | None | 34 | 18 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8236 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GOVERNOR SYSTEM | None | 35 | 18 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8236 | 99024410 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVISORY | None | 36 | 18 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | None | 37 | 18 | No Level 2 required - include in steam turbine overhaul (Assuming SSR is replaced in 2013). | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8248 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | None | 38 | 18 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |
| 1296 | 8193 | 8194 | 271675 | 8250 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE TURNING GEAR | None | 39 | 18 | No Level 2 required - include in steam turbine overhaul. | 2013 | | |

### 10.2.9.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 steam turbine include:

**TABLE 10-71 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – UNIT 3 STEAM TURBINE**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | N/A | 30 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | N/A | 31 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | N/A | 32 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | N/A | 33 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | N/A | 34 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8217 | 0 | 3 | U3 GENERATOR | TURBINE | L.P. TURBINE | N/A | 35 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8230 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE FRONT STANDARD | N/A | 36 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8236 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GOVERNOR SYSTEM | N/A | 37 | 18 | 3 | Upgrade the mechanical fly-ball type turbine governor system to as-built condition or be replaced using electronic controls. | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 99024410 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVI | N/A | 38 | 18 | 3 | Implement replacement option. | 2013 | 2 |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | N/A | 39 | 18 | 3 | Replace steam seal regulator | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8248 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE PRE-WARMING SYSTEM | N/A | 40 | 18 | 3 | No capital required. | | |
| 1296 | 8193 | 8194 | 271675 | 8250 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE TURNING GEAR | N/A | 41 | 18 | 3 | No capital required. | | |

### 10.2.10 Asset 271768 – Cooling Water System - Associated with Steam Systems

(Detailed Technical Assessment in Working Papers, Appendix 11, 25)

| | |
|---|---|
| Unit #: | 3 |
| Asset Class # | BU 1296 - Assets Generations |
| SCI & System: | 8645 #3 Unit Generation Services |
| Sub-Systems: | 271678 #3 CW System |
| Components: | 8649 #3 CW Travelling Screens East |
| | 8650 #3 CW Travelling Screens West |
| | 8658 #3 CW Pump East |
| | 8659 #3 CW Pump West |
| | 8647#3 CW Intake (Pipe from CW Pumps) |
| | 8676 #3 CW Discharge to Outfall (Piping from Condenser) |

#### 10.2.10.1 Description

The circulating water (CW) systems, servicing Unit 3 consist of two 50% CW vertical turbine pumps driven by 4kV motors and auxiliary systems. The pump drive motors are original. Two travelling screen systems are used to remove debris from the cooling water prior to entering the pumps. The primary function of the CW system is to provide condenser cooling water but also cooling water for other closed loop systems. It is necessary that the CW system operate efficiently in order to maintain optimal plant thermal efficiency by minimizing steam turbine condenser backpressures.

The requirements for Unit are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Next Major Overhaul/Inspection | 2016 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |



FIGURE 10-26 UNIT 3 CIRCULATING WATER INLET



FIGURE 10-27 UNIT 3 CIRCULATING WATER TRAVELLING SCREENS



FIGURE 10-28 UNIT 3 CIRCULATING WATER PUMPS

### 10.2.10.2 History

The requirements for the cooling water system on Units 3 are as follows:

| | |
|---|---|
| Manufactured/Delivered | 1979 |
| In-Service Date | Feb 1980 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |

The hours associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual - Ops to Dec 2009 | 126 |
| Max Hours Generation Ops – to Dec 2015 | 170 |
| Max Hrs Gen Ops to Gen End Date Dec 2020 | 179 |

### 10.2.10.3 Inspection and Repair History

**Cooling Water Pumps & Motors, Screens, and Piping Systems**

**Asset 8649/8650 CW Travelling Screens**

The Unit 3 CW pumps and motors, screens, and piping systems have not been refurbished. The screens on Unit 3 have not been refurbished and likely should be within next five years.

The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short term performance.

**Asset 6823 Wash Water Pumps and Motors**

Externally, the wash water pumps and motors are generally in a corroded state, but were performing at the time of the visual inspection. They are considered to be a minor maintenance issue and not addressed as a part of this assessment.

**Asset 8858/8859 CW Pumps**

The CW pumps servicing Unit 3 are performing fairly well. No reports were available on the condition of the pumps, but interviews suggest that regular maintenance has been kept up and the units should be able to meet 2015 and 2020 timelines with satisfactory maintenance. Major pump overhauls are scheduled on a twelve year cycle.

**TABLE 10-72 MAJOR PUMP OVERHAULS**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Pumps | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
| 1 CW Pump East | | | X | | | | | | | | | | | | 83,000.00 | | | |
| 1 CW Pump West | | | | | | | | | | | 75,000.00 | | | | | | | |
| 2 CW Pump East | X | | | | X | | | | | | | | | | | | 87,000.00 | |
| 2 CW Pump West | | | | | | | | | | | | 77,000.00 | | | | | | |
| 3 CW Pump East | | X | | | | | | | | | 75,000.00 | | | | | | | |
| 3 CW Pump West | | | | | | 10,000.00 | | | | | | | | | | | | 89,000.00 |

**CW Pump Motors:** Motors are electrically tested every year as a component of the plant PM process. See 4 kV motor discussion in Appendix 25.

**CW Pump Outlet Piping, Valves & Fittings:** Outlet piping, valves and fittings from the pump discharge to the inlet of the 64 inch concrete piping that is installed underground to the unit condensers has generally experienced significant degrees of corrosion and some patching of the system has been done. It is in need of clean-up and a Level 2 inspection, or perhaps a complete replacement.

**Asset 8647/6678 Cooling Water System Intake & Discharge**

The 36 inch and 64 inch CW intake and discharge concrete piping that goes underground to the Unit 3 condenser has periodically been pumped out and walked down by plant staff, although not in the last five years. There have been no obvious issues with the system, although no detailed engineering evaluations and NDE work have been undertaken.

No specific corrosion, spalling, cracks or fractures were identified, and no patching of the system has been done. Inspections are planned going forward on a three year frequency as per the schedule below.

**TABLE 10-73 ANNUAL ASSET MAINTENANCE**

| Annual Asset Maintenance | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CW Inspection | | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
| | | | | | | | | | | | | | | | | | |
| Unit 1 | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 | |
| Unit 2 | | | | | | | | | | | | | | 25,625.00 | | | 26,625.00 |
| Unit 3 | | | | | | | | | | | | 25,000.00 | | | 25,625.00 | | |
| | | | | | | | | | | | | | | | | | |

### 10.2.10.4 Condition Assessment

The condition assessment of the Unit 3 cooling water system associated with steam systems is illustrated below in Table 10-74.

**TABLE 10-74 CONDITION ASSESSMENT – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset Level 2 | Asset Level 3 | Description | Detail | Condition Summary ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul or Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 142 | 11 | | | | | | | | | | |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Concrete pipe from Pumps to Condenser | 143 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize mussel growth on the CW pipe internally. | 4 | (60) | (20+) | 2041 | | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Concrete pipe from Condenser to outfall pit | 144 | 11 | No recent inspections of cement pipes, but walk-downs about 5 years ago indicated that the pipe looked intact. Some moderate issues with stop log structures were identified. Given the geotechnical conditions and soil, there is no reason to expect any kind of aggressive attack. A copper ion system was installed to minimize mussel growth on the CW pipe internally. | 4 | (60) | (20+) | 2041 | | 2011 | Yes | Yes | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 145 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1980 |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 146 | 11 | The CW pumps have major inspections and overhauls about every twelve years. The motors are electrically checked annually per their PM requirements. Overall the pumps and motors seem to be performing satisfactorily. Several patches are evident on the CW steel pipes and valves associated with the pumps. | 3a | (30) | 10 | 2020 | 2012 | | Yes | Yes | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where cells are blank, the dates may be either not scheduled or simply are not known to AMEC.

### 10.2.10.5 Actions

Based on the condition assessment, the following actions are recommended for the Unit 3 cooling water system associated with steam systems.

**TABLE 10-75 RECOMMENDED ACTIONS – COOLING WATER SYSTEM ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 271678 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 213 | 11 | Maintain ongoing inspection and maintenance programs It is recommended that a spare 4 kV motor be maintained to service all three units, in the event of a failure of an existing unit.. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8647 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE SYSTEM | N/A | 214 | 11 | Perform a detailed visible inspection, with some NDE spotchecks, within the next two to four years of the concrete intake and discharge pipes. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW DISCHARGE TO OUTFALL | N/A | 215 | 11 | Perform a detailed visible inspection, with some NDE spotchecks of the concrete intake and discharge pipes. | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8658 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Pipe | 216 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8659 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Pipe | 217 | 11 | Clean CW steel pipe and check thickness measurements (Level 2). | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8658 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | N/A | 218 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2011 | 2 |
| 1296 | 8193 | 8645 | 271678 | 8659 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | N/A | 219 | 11 | Perform planned CW pump inspections on one pump per unit in 2010 to 2012 (Level 2). | 2012 | 2 |
| 1296 | 8193 | 8645 | 271678 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | N/A | 220 | 11 | Maintain ongoing inspection and maintenance programs. | 2011 | 2 |

### 10.2.10.6 Risk Assessment

The risk assessment associated with the Unit 3 cooling water system – associated with steam systems, both from a technological perspective and a safety perspective, is illustrated below in Table 10-76.

**TABLE 10-76 RISK ASSESSMENT – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | TECHNO_ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Unit #3 CW Concrete Pipe to Condenser | 182 | 11 | Concrete racking. | (20+) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Unit #3 CW Pipe to Outfall Structure | 183 | 11 | Concrete racking. | (20+) | None | 1 | B | Low | 1 | A | Low | Cracking or failure – major leak requiring repair. | Inspect and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Unit #3 CW Pumps | 184 | 11 | Corrosion-internal/ext. | 10+ | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | 4 kV Cooling Water Pump Motor | 185 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | B | Low | 1 | A | Low | Loss 60% unit generation. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Unit #3 CW Outlet Piping, Valves, Fittings | 186 | 11 | Corrosion-internal/ext. | 5+ | None | 3 | A | Low | 3 | A | Low | Major leak and repair/patch. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Unit #3 CW Pumps | 187 | 11 | Corrosion-internal/ext. | 10+ | None | 2 | B | Low | 2 | A | Low | 50% unit output loss while replaced with spare. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | 4 kV Cooling Water Pump Motor | 188 | 25 | Electrical fault, mechanical fatigue, ops error. | 5+ | None | 2 | B | Low | 1 | A | Low | Loss 60% unit generation. | Current inspection and maintain. |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Unit #3 CW Outlet Piping, Valves, Fittings | 189 | 11 | Corrosion-internal/ext. | 5+ | None | 3 | A | Low | 3 | A | Low | Major leak and repair/patch. | Inspect and maintain. |

### 10.2.10.7 Life Cycle Curve and Remaining Life

The life cycle curve for the Unit 3 cooling water system associated with steam systems is illustrated below. One curve represents all the major elements of the system which are about the same age. No information existed on the condition of the large CW pipe to and from the condensers. Although it was not plotted here, its life would be expected to be on the order of 50 years, given no incidents to date as a result of original poor design or installation. The life curve is a plot of current and projected operating hours (generation mode only) on the y-axis versus calendar year on the x-axis. The figure has vertical lines representing differing representative nominal age limits. It also has several horizontal lines that represent a range of practical equivalent base loaded operating hour life limits. Both limits can come into play and both are extendable through maintenance refurbishment and component replacement. The risk area box provides an indication of the timing of potential issues either from an age or equivalent operating hours view.

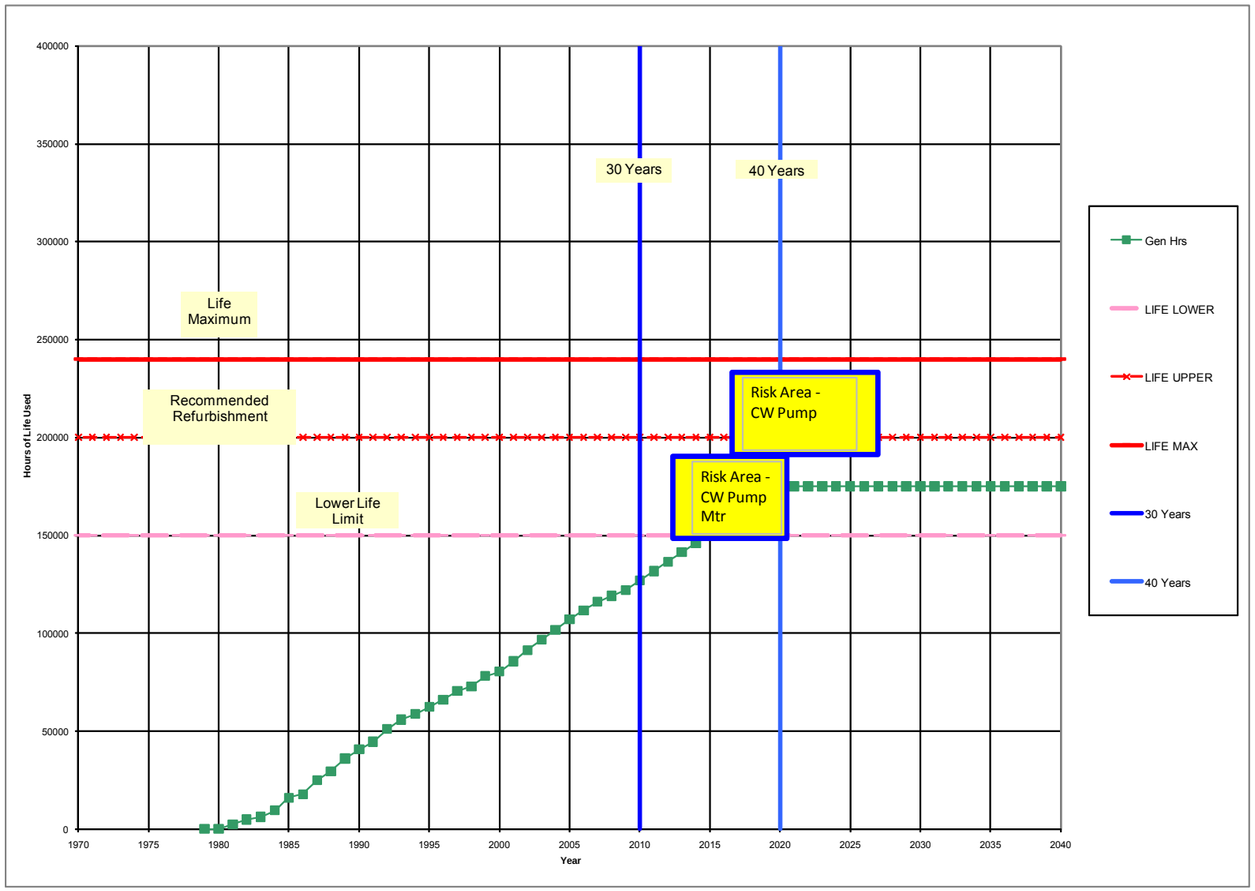



**FIGURE 10-29 LIFE CYCLE CURVE – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

The curves indicate that the remaining life (RL) of the Unit 3 cooling water system - associated with steam systems can likely reach the desired life (DL) end date for generation of 2020, but with some reliability risk, particularly as it pertains to the 4 kV motors. It is recommended that a spare motor shared between units would be a reasonable precaution. Corrosion of the steel pipe, valves, and fittings was also evident suggesting that some maintenance on these issues is required.

### 10.2.10.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 10-77 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 10-77 LEVEL 2 INSPECTION – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Concrete Pipe to/from pump to condenser | 171 | 11 | Inspections - dry walk-down and NDE spotcheck. | 2011 | 2 | $6 |
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Steel Pipe to/from condenser | 172 | 11 | Clean steel pipe and check thickness measurements. | 2011 | 2 | |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | CW Pumps | 173 | 25 | Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2 like). No Level 2 on 4 kV motor if current maintenance program continues | | | |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | CW Pumps | 174 | 25 | Perform planned inspections on one pump per unit in 2010 to 2012 (Level 2 like). No Level 2 on 4 kV motor if current maintenance program continues | | | |

### 10.2.10.9 Capital Projects

The suggested typical capital enhancements for the Unit 3 cooling water system associated with steam systems include:

**TABLE 10-78 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COOLING WATER SYSTEM - ASSOCIATED WITH STEAM SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Detail | CAP# | Appendix # | Unit # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | | 141 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Concrete Pipe from pump to Condenser | 142 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Concrete Pipe from condenser to CW Outfall pit | 143 | 11 | 3 | No capital required. | | |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP EAST | N/A | 144 | 25 | 3 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. PUMP WEST | N/A | 145 | 25 | 3 | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical. | 2012 | 1 |

# 11 COMMON SYSTEMS

## 11.1 Common Systems - Key Systems

### 11.1.1 Asset 1325: 5990 to 6052 – Switchyard Switchgear

(Detailed Technical Assessment in Working Papers, Appendix 7)

| | |
|---|---|
| Unit #: | Common |
| Asset Class # | BU 1325 – Holyrood Switchyard |
| Components: | 5990-6007 Switchyard Breakers<br>6008-6041 275789 Motorized Disconnect Switches<br>6042-6053 Manual Disconnect Switches |

#### 11.1.1.1 Description

The switchyard electrical and controls assets that are itemized in the Holyrood Present State Asset List and the electrical and control systems/equipment associated with the switchyard are generally shown in the same order as Hydro's Present State Asset List. The station single line diagrams should be consulted to provide the electrical locations in the switchyard:

**230kV Breakers:** Breakers B12L17, B2L42, B1L17 are Brown Boveri, Air Blast type DLF 245 nc2, installed in 1973. Additional breakers were subsequently identified as B1B11, B2B11, B12B42, B3L18, B3B13, and B12B15 (Air Blast Breakers). The following are SF6 Breakers: B13B15, B12L18, B12T10.

**138kV Breakers:** Breaker B8L39 is CGE Oil type, KSO-138-5000, and installed in 1978.

**69kV Breakers**

- Breakers B7L38, B7L2 are CGE Oil type KSO-69-1500 and installed in 1969;
- Breaker B6L3 is CGE Oil type FKP and installed in 1978; and
- Breakers B7T5, B6T10 are AEG SF6 type DT1-72F1 and installed in 1996.

**230kV Motorized Disconnects**

- Motorized disconnects B11T5, B15T6 are Raised Vertical Break type Kearney RVB, c/w Kearney KMT operator, vintage 1969-1978;
- Motorized disconnect B15T7 is Raised Vertical Break type Kearney AVB, c/w ITE MO-10X operator, vintage 1969-1978;
- Motorized disconnects B12T10-1, B15T8 are Raised Vertical Break type Siemens AVB, c/w Siemens CM-4A operator, vintage 1969-1978;

- Motorized disconnects B12B15-1, B12B15-2, B12L18-1, B12L18-2, B13B15-1, B13B15-2, B1T1, B3L18-1, B3L18-2, B2T2, B3B13-1, B3B13-2, B3T3 are Double Horizontal Break type Kearney DHB, c/w Kearney KMT operator, vintage 1969-1978; and
- Motorized disconnects B12L17-1, B12L17-2, B12L42-1, B12L42-2, B1B11-1, B1B11-2, B1L17-1, B1L17-2, B2B11-1, B2B11-2, B2L42-1, B2L42-2 are Horizontal Center Break type Kearney CHB, c/w Kearney KMT operator, vintage 1969-1978. The following maintenance has been recorded as completed by the JDE.

**138kV Motorized Disconnects**

- Motorized disconnects B8T6, B8T7, B8T8 are Raised Vertical Break type Joslyn RF-2, c/w Joslyn JMO operator, vintage 1969-1978.







**FIGURE 11-1 HOLYROOD SWITCHYARD**

The switchyard compressed air system includes

- Air Compressor A
- Air Compressor B
- Air Compressor C
- Compressed Air Distribution Piping

#### 11.1.1.2 Inspection and Repair History

The hours associated with the various systems and equipment varies as parts have been replaced and/or refurbished over the years. The majority of equipment is over 15 years old. However it is regularly tested and inspected based on the Hydro's PM protocol. The switchyard switchgear is functional and in reasonable condition. The equipment will be required through to 2041 so it will require extensive refurbishment and/or replacement.

The switchyard compressor air supply distribution piping for the air blast breakers is originally copper and in the past, it has been necessary to replace corroded sections with a flexible hose material know as synflex. Corrosion has led to compressed air dew point problems. Hydro currently has a capital project in progress to replace (2010/2011) the copper piping with a welded stainless system and install a redundant air dryer and an online dew point monitoring system.

### 11.1.1.3 Condition Assessment

The condition assessment of the switchyard switchgear is illustrated below in Table 11-1.

**TABLE 11-1 CONDITION ASSESSMENT – SWITCHYARD SWITCHGEAR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | HRDB3B13 | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | N/A | 179 | 7 | Sanded & painted in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Washed in 2004. Capacitor replaced in 2008. Doble test in 2009. | 3a | (40) | 8 | 2041 | 2014 | 2014 | Yes | No | 1978 |
| 1325 | 5991 | 5991 | 310-77-3 | HRDB12B15 | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | N/A | 180 | 7 | Sanded & painted in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Doble test in 2001. Capacitor replaced in 2001. Washed in 2004. Safety relief valve replaced in 2007. | 3a | (40) | 8 | 2041 | 2014 | 2014 | Yes | No | 1978 |
| 1325 | 5992 | 5992 | 460-80 AD/2 | HRDB12L18 | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | N/A | 181 | 7 | Solenoid valve replaced in 1999. P3 Maintenance performed in 2001. Doble test in 2001. Indication repaired in 2003. Sanded and painted in 2003. Washed in 2004. Air leak repaired in 2004. Breaker mechanism overhauled and planned maintenance performed in 2006. | 3a | (40) | 11 | 2041 | 2012 | 2012 | Yes | No | 1981 |
| 1325 | 5993 | 5993 | 310-77-2 | HRDB3L18 | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | N/A | 182 | 7 | Sanded and painted in 1999 and 2003. Indication repaired in 2001. P3 maintenance in 2001. Capacitor replaced in 2001 and 2003. Drain valve replaced in 2003. Washed in 2004. Planned maintenance performed in 1985 and 1991. | 3a | (40) | 8 | 2041 | 2011 | 2011 | Yes | No | 1978 |
| 1325 | 5994 | 5994 | 170-73-3 | HRDB1L17 | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | N/A | 183 | 7 | P3 maintenance performed in 2001. Jumpers replaced in 2001. Doble test in 2001. Air leak repaired in 2003. Sanded and painted in 2003. Control valve leak repaired in 2003. Washed in 2004. PLC control installed in 2007. Operation check in 2007. Protection and time tests performed in 2007. Planned maintenance performed in 2006. Trip coil contacts cleaned in 2009. | 3a | (40) | 3 | 2041 | 2012 | 2012 | Yes | No | 1973 |
| 1325 | 5995 | 5995 | 310-77-4 | HRDB12L42 | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | N/A | 184 | 7 | Sanded & painted in 1999 and 2003. P3 maintenance performed in 2000. Doble test in 2000 and 2009. Washed in 2004. Air leak repaired in 2007. Planned maintenance performed in 2008. | 3a | (40) | 8 | 2041 | 2014 | 2014 | Yes | No | 1978 |
| 1325 | 5996 | 5996 | 188-74-2 | HRDB2B11 | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | N/A | 185 | 7 | Sanded & painted in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Capacitor replaced in 2004. Washed in 2004. Handle replaced in 2007. Indication repair in 2007. RTV coating in 2006. Hinges replaced in 2008. Relief valve replaced in 2009. Planned maintenance performed in 2009. | 3a | (40) | 6 | 2041 | 2015 | 2015 | Yes | No | 1974 |
| 1325 | 5997 | 5997 | 188-74-1 | HRDB1B11 | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | N/A | 186 | 7 | Sanded & painted in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Fuse holder replace in 2003. Indication relay replaced in 2004. Washed in 2004. Capacitor replaced in 2007. Pressure reducing valve replaced in 2007. Hinges replaced in 2008. RTV coating in 2006. Planned maintenance performed in 2007. Heat trace replaced in 2008. Relief valve replaced in 2009. | 3a | (40) | 4 | 2041 | 2014 | 2014 | Yes | No | 1974 |
| 1325 | 5998 | 5998 | 170-73-2 | HRDB12L17 | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | N/A | 187 | 7 | Pressure reducing valve replaced in 1999. Sanded & painted in 1999 and 2003. Washed in 2004. Leslie valve regulator replaced in 2006. Planned maintenance performed in 2008. Relief valve replaced in 2009. Doble tested in 2009. | 3a | (40) | 7 | 2041 | 2015 | 2015 | Yes | No | 1973 |
| 1325 | 5999 | 5999 | 170-73-1 | HRDB2L42 | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | N/A | 188 | 7 | Sanded & painted in 1999 and 2003. P3 maintenance performed in 2001. Washed in 2004. Doble tested in 2004. Indication repaired in 2007. Capacitor replaced in 2008. Relief valve replaced in 2009. Planned Maintenance performed in 2009. | 3a | (40) | 7 | 2041 | 2015 | 2015 | Yes | No | 1973 |
| 1325 | 6000 | 6000 | 0464DT72 | HRDB6T10 | HRDTS | BREAKER,B6T10,HRD TS | 69 KV | N/A | 189 | 7 | P3 Maintenance performed in 2001. Sanded and painted in 2001 and 2007. Moisture heater installed in 2007. | 3a | (40) | 26 | 2041 | 2011 | 2011 | Yes | No | 1996 |
| 1325 | 6001 | 6001 | 90/K31238935 | HRDB12T10 | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | N/A | 190 | 7 | P3 Maintenance performed in 2000. Washed in 2004. Contacts replaced in 2006. Hydraulic overhaul in 2007. Planned maintenance performed in 2007. | 3a | (40) | 20 | 2041 | 2013 | 2013 | Yes | No | 1990 |
| 1325 | 6002 | 6002 | 45510DD/1 | HRDB13B15 | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | N/A | 191 | 7 | Sanded & painted in 2000 and 2003. P3 maintenance performed in 2001 and 2007. Doble tests in 2001 and 2007. Indications repaired in 2002. New thermostat installed in 2004. Washed in 2004. Fittings and hoses replaced in 2006. Drive mechanism overhaul in 2007. Planned maintenance performed in 2007. | 3a | (40) | 11 | 2041 | 2013 | 2013 | Yes | No | 1981 |
| 1325 | 6003 | 6003 | 0465DT72 | HRDB7T5 | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | N/A | 192 | 7 | P3 Maintenance performed in 2000. Sanded and painted in 2001. Cabinet heater installed in 2007. Planned maintenance performed in 2009. | 3a | (40) | 26 | 2041 | 2015 | 2015 | Yes | No | 1996 |
| 1325 | 6004 | 6004 | 61130 | HRDB7L2 | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | N/A | 193 | 7 | P3 (PM) Maintenance performed in 2001. Oil sample taken in 2007. (PM completed in 2010, but not availab at time of report.) | 3a | (40) | 5 | 2041 | 2011 | 2011 | Yes | No | 1969 |
| 1325 | 6005 | 6005 | 63257 | HRDB8L39 | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | N/A | 194 | 7 | Mounting bracket replaced in 1999. Doble test in 2001. P3 Maintenance in 2001. Revised trip interlock circuit in 2001. Breaker overhaul in 2002 (ref. WO#241903). Junction box replaced in 2002. Planned maintenance performed in 2005 and 2008. Oil sample taken in 2007. | 3a | (40) | 8 | 2041 | 2014 | 2014 | Yes | No | 1978 |
| 1325 | 6006 | 6006 | 64018 | HRDB6L3 | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | N/A | 195 | 7 | P3 Maintenance performed in 2000. Doble test in 2000. Oil sample taken in 2007. Gaskets replaced in 2009. Planned maintenance performed in 2009. | 3a | (40) | 8 | 2041 | 2015 | 2015 | Yes | No | 1978 |
| 1325 | 6007 | 6007 | 61131 | HRDB7L38 | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | N/A | 196 | 7 | P3 Maintenance performed in 2001. Oil sample taken in 2007. (PM completed in 2010, but not availab at time of report.) | 3a | (40) | 5 | 2041 | 2011 | 2011 | Yes | No | 1969 |

Table 11-1 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6008 | 6008 | | HRDB12L17-1 | HRDTS | DISCONNECT,B12L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 199 | 7 | Brake coil replaced in 1999. Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Cabinet heater replaced in 2003. Grease nipples installed in 2006. Planned maintenance performed in 2006. Adjusted and checked in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6009 | 6009 | | HRDB12L42-1 | HRDTS | DISCONNECT,B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 200 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Operation repaired in 2003. Blade clamp assembly repaired in 2007. Gearbox repaired in 2007. Grease nipples installed in 2006. Function tested in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6010 | 6010 | | HRDB2L42-1 | HRDTS | DISCONNECT,B2L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 201 | 7 | Gearbox repaired 2004. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6011 | 6011 | | HRDB2B11-1 | HRDTS | DISCONNECT,B2B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 202 | 7 | DC motor contacts cleaned in 2001. Gearbox replaced in 2002. Grease nipples installed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6012 | 6012 | | HRDB2B11-2 | HRDTS | DISCONNECT,B2B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 203 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Grease nipples installed in 2009. Planned maintenance performed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6013 | 6013 | | HRDB12L17-2 | HRDTS | DISCONNECT,B12L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 204 | 7 | Grease nipples installed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6014 | 6014 | | HRDB2L42-2 | HRDTS | DISCONNECT,B2L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 205 | 7 | Planned maintenance performed in 2008. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6015 | 6015 | | HRDB1L17-2 | HRDTS | DISCONNECT,B1L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 206 | 7 | Ground switch repaired in 2006. Grease nipples installed in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6016 | 6016 | | HRDB12L42-2 | HRDTS | DISCONNECT,B12L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 207 | 7 | Contacts blade replaced in 2000. Grease nipples installed in 2008. Planned maintenance performed in 2008. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6017 | 6017 | | HRDB1L17-1 | HRDTS | DISCONNECT,B1L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 208 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased alignment in 2000. Motor/Manual button repaired in 2003. Grease nipples installed in 2006, 2007, and 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6018 | 6018 | | HRDB1B11-1 | HRDTS | DISCONNECT,B1B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 209 | 7 | Brake coil replaced in 2001. Grease nipples installed in 2007. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6019 | 6019 | | HRDB12T10-1 | HRDTS | DISCONNECT,B12T10-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 210 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. Grease nipples installed in 2006. Function test performed in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6020 | 6020 | | HRDB12L18-1 | HRDTS | DISCONNECT,B12L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 211 | 7 | Blade assembly repaired in 1999. Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. DC motor contacts cleaned in 2001. Grease nipples installed in 2006. Function tested in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6021 | 6021 | | HRDB12B15-2 | HRDTS | DISCONNECT,B12B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 212 | 7 | Jumpers replaced in 2007. Infrared scan in 2007. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6022 | 6022 | | HRDB13B15-2 | HRDTS | DISCONNECT,B13B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 213 | 7 | Disconnect alignment checked in 2004. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6023 | 6023 | | HRDB3L18-2 | HRDTS | DISCONNECT,B3L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 214 | 7 | C phase arm repaired in 2001. Doble test in 2002. Planned maintenance in 2002. Heater circuit repaired in 2003. Grease nipples installed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6024 | 6024 | | HRDB3L18-1 | HRDTS | DISCONNECT,B3L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 215 | 7 | Pedestal welding repaired in 2009. Grease nipples installed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6025 | 6025 | | HRDB3B13-1 | HRDTS | DISCONNECT,B3B13-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 216 | 7 | Contacts greased and cleaned in 2000. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6026 | 6026 | | HRDB3B13-2 | HRDTS | DISCONNECT,B3B13-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 217 | 7 | Blades cleaned and greased in 2001. Seized arm repaired in 2001. Linkages repaired in 2007. Grease nipples installed in 2009. Function test in 2009. Planned maintenance performed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6027 | 6027 | | HRDB13B15-1 | HRDTS | DISCONNECT,B13B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 218 | 7 | Spring replaced in 2001. Disconnect cleaned in 2001. Jumpers replaced in 2002. Grease nipples installed in 2009. Function test in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6028 | 6028 | | HRDB12B15-1 | HRDTS | DISCONNECT,B12B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 219 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, alignment in 2000. Grease nipples installed in 2006. Function test performed in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6029 | 6029 | | HRDB1B11-2 | HRDTS | DISCONNECT,B1B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 220 | 7 | Planned maintenance performed in 2009. Grease nipples installed in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6030 | 6030 | | HRDB11T5 | HRDTS | DISCONNECT,B11T5,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 221 | 7 | Greased, and main contacts and aux contacts cleaned in 2001. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6031 | 6031 | | HRDB8T6 | HRDTS | DISCONNECT,B8T6,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 222 | 7 | Planned maintenance was performed in 2002. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6032 | 6032 | | HRDB8T7 | HRDTS | DISCONNECT,B8T7,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 223 | 7 | Planned maintenance was performed in 2002. Heater circuit repaired in 2003. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6033 | 6033 | | HRDB8T8 | HRDTS | DISCONNECT,B8T8,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 224 | 7 | Planned maintenance was performed in 2002. Phase B aligned in 2004. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6034 | 6034 | | HRDB15T6 | HRDTS | DISCONNECT,B15T6,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 225 | 7 | Function test and planned maintenance performed in 2002. Alignment in 2007. Cam switch repaired in 2007. DC motor replaced in 2009. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6035 | 6035 | | HRDB3T3 | HRDTS | DISCONNECT,B3T3,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 226 | 7 | Contacts cleaned and greased in 2000. Heating wiring repaired in 2004. Jaws assembly replaced in 2005 and 2010. Arm inserts replaced in 2007. Brakes cleaned in 2006. Broken linkage pin replaced in 2006. Alignment in 2007. Ground switch lubricated in 2008. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6036 | 6036 | | HRDB15T8 | HRDTS | DISCONNECT,B15T8,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 227 | 7 | Function test and planned maintenance performed in 2002. Cabinet heater installed in 2004. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6037 | 6037 | | HRDB2T2 | HRDTS | DISCONNECT,B2T2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 228 | 7 | DC motor contacts cleaned in 2001. Greased and function tested in 2006. Brakes replaced in 2007. Gear box ground switch replaced in 2007. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6038 | 6038 | | HRDB1T1 | HRDTS | DISCONNECT,B1T1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 229 | 7 | Disc adjusted in 2001. Cabinet repaired in 2002. Locking and chaining wheel adjusted in 2003. Indications repaired in 2003. Cam switches greased and aligned in 2003 and then adjusted in 2007. DC switch cleaned in 2007. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6039 | 6039 | | HRDB15T7 | HRDTS | DISCONNECT,B15T7,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 230 | 7 | Function tested and planned maintenance performed in 2002. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6040 | 6040 | | HRDB8L39-2 | HRDTS | DISCONNECT,B8L39-2,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 231 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6041 | 6041 | | HRDB8L39-1 | HRDTS | DISCONNECT,B8L39-1,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 232 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |

Table 11-1 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6042 | 6042 | | HRDB7T5-2 | HRDTS | DISCONNECT,B7T5-2,HRD TS | 69 KV | Manual Operated HV Switch | 235 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6043 | 6043 | | HRDL2L38 | HRDTS | DISCONNECT,L2L38,HRD TS | 69 KV | Manual Operated HV Switch | 236 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6044 | 6044 | | HRDB7L38-1 | HRDTS | DISCONNECT,B7L38-1,HRD TS | 69 KV | Manual Operated HV Switch | 237 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6045 | 6045 | | HRDB7L38-2 | HRDTS | DISCONNECT,B7L38-2,HRD TS | 69 KV | Manual Operated HV Switch | 238 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6046 | 6046 | | HRDB7L2-2 | HRDTS | DISCONNECT,B7L2-2,HRD TS | 69 KV | Manual Operated HV Switch | 239 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6047 | 6047 | | HRDB7L2-1 | HRDTS | DISCONNECT,B7L2-1,HRD TS | 69 KV | Manual Operated HV Switch | 240 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6048 | 6048 | | HRDB6L3-1 | HRDTS | DISCONNECT,B6L3-1,HRD TS | 69 KV | Manual Operated HV Switch | 241 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6049 | 6049 | | HRDB6L3-2 | HRDTS | DISCONNECT,B6L3-2,HRD TS | 69 KV | Manual Operated HV Switch | 242 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6050 | 6050 | | HRDB6B7 | HRDTS | DISCONNECT,B6B7,HRD TS | 69 KV | Manual Operated HV Switch | 243 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6051 | 6051 | | HRDB7T5-1 | HRDTS | DISCONNECT,B7T5-1,HRD TS | 69 KV | Manual Operated HV Switch | 244 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6052 | 6052 | | HRDB6T10-1 | HRDTS | DISCONNECT,B6T10-1,HRD TS | 69 KV | Manual Operated HV Switch | 245 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6053 | 6053 | | HRDB11B13 | HRDTS | DISCONNECT,B11B13,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 246 | 7 | Not reviewed in detail. No specific issues or maintenance identified. Maintained per requirements. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 6546 | 6546 | | HRDB12L18-2 | HRDTS | DISCONNECT,B12L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 247 | 7 | Hand wheel lubricated in 2001. Wiring repaired in 2001. Doble tested 2002. Planned maintenance performed in 2002. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |
| 1325 | 275789 | 275789 | | HRDB12L42-1 | HRDTS | DISCONNECTS B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 248 | 7 | Greased, main contacts and aux contacts cleaned, bearing assembly and linkage cleaned and greased, and alignment in 2000. Operation repaired in 2003. Blade clamp assembly repaired in 2007. Gearbox repaired in 2007. Grease nipples installed in 2006. Function tested in 2006. | 3a | (40) | 10 | 2041 | N/A | N/A | Yes | No | 1969-1978 |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

#### 11.1.1.4 Actions

Based on the condition assessment, the following actions are recommended for the switchyard switchgear:

**11-2 RECOMMENDED ACTIONS – SWITCHYARD SWITCHGEAR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | HRDB3B13 | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | 180 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5991 | 5991 | 310-77-3 | HRDB12B15 | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | 181 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5992 | 5992 | 460-80 AD/2 | HRDB12L18 | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | 182 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5993 | 5993 | 310-77-2 | HRDB3L18 | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | 183 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5994 | 5994 | 170-73-3 | HRDB1L17 | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | 184 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5995 | 5995 | 310-77-4 | HRDB12L42 | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | 185 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5996 | 5996 | 188-74-2 | HRDB2B11 | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | 186 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5997 | 5997 | 188-74-1 | HRDB1B11 | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | 187 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5998 | 5998 | 170-73-2 | HRDB12L17 | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | 188 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 5999 | 5999 | 170-73-1 | HRDB2L42 | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | 189 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6001 | 6001 | 90/K31238935 | HRDB12T10 | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | 190 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6002 | 6002 | 45510DD/1 | HRDB13B15 | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | 191 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6005 | 6005 | 63257 | HRDB8L39 | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | 193 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6003 | 6003 | 0465DT72 | HRDB7T5 | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | 195 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |

Table 11-2 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6004 | 6004 | 61130 | HRDB7L2 | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | 196 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6006 | 6006 | 64018 | HRDB6L3 | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | 197 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6007 | 6007 | 61131 | HRDB7L38 | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | 198 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6008 | 6008 | 6008 | HRDB12L17-1 | HRDTS | DISCONNECT,B12L17-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 202 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6009 | 6009 | 6009 | HRDB12L42-1 | HRDTS | DISCONNECT,B12L42-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 203 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6010 | 6010 | 6010 | HRDB2L42-1 | HRDTS | DISCONNECT,B2L42-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 204 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6011 | 6011 | 6011 | HRDB2B11-1 | HRDTS | DISCONNECT,B2B11-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 205 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6012 | 6012 | 6012 | HRDB2B11-2 | HRDTS | DISCONNECT,B2B11-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 206 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6013 | 6013 | 6013 | HRDB12L17-2 | HRDTS | DISCONNECT,B12L17-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 207 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6014 | 6014 | 6014 | HRDB2L42-2 | HRDTS | DISCONNECT,B2L42-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 208 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6015 | 6015 | 6015 | HRDB1L17-2 | HRDTS | DISCONNECT,B1L17-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 209 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6016 | 6016 | 6016 | HRDB12L42-2 | HRDTS | DISCONNECT,B12L42-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 210 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6017 | 6017 | 6017 | HRDB1L17-1 | HRDTS | DISCONNECT,B1L17-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 211 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6018 | 6018 | 6018 | HRDB1B11-1 | HRDTS | DISCONNECT,B1B11-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 212 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6019 | 6019 | 6019 | HRDB12T10-1 | HRDTS | DISCONNECT,B12T10-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 213 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6020 | 6020 | 6020 | HRDB12L18-1 | HRDTS | DISCONNECT,B12L18-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 214 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6021 | 6021 | 6021 | HRDB12B15-2 | HRDTS | DISCONNECT,B12B15-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 215 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6022 | 6022 | 6022 | HRDB13B15-2 | HRDTS | DISCONNECT,B13B15-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 216 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6023 | 6023 | 6023 | HRDB3L18-2 | HRDTS | DISCONNECT,B3L18-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 217 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6024 | 6024 | 6024 | HRDB3L18-1 | HRDTS | DISCONNECT,B3L18-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 218 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6025 | 6025 | 6025 | HRDB3B13-1 | HRDTS | DISCONNECT,B3B13-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 219 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6026 | 6026 | 6026 | HRDB3B13-2 | HRDTS | DISCONNECT,B3B13-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 220 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |

Table 11-2 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6027 | 6027 | 6027 | HRDB13B15-1 | HRDTS | DISCONNECT,B13B15-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 221 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6028 | 6028 | 6028 | HRDB12B15-1 | HRDTS | DISCONNECT,B12B15-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 222 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6029 | 6029 | 6029 | HRDB1B11-2 | HRDTS | DISCONNECT,B1B11-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 223 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6030 | 6030 | 6030 | HRDB11T5 | HRDTS | DISCONNECT,B11T5,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 224 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6034 | 6034 | 6034 | HRDB15T6 | HRDTS | DISCONNECT,B15T6,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 225 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6035 | 6035 | 6035 | HRDB3T3 | HRDTS | DISCONNECT,B3T3,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 226 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6036 | 6036 | 6036 | HRDB15T8 | HRDTS | DISCONNECT,B15T8,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 227 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6037 | 6037 | 6037 | HRDB2T2 | HRDTS | DISCONNECT,B2T2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 228 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6038 | 6038 | 6038 | HRDB1T1 | HRDTS | DISCONNECT,B1T1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 229 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6039 | 6039 | 6039 | HRDB15T7 | HRDTS | DISCONNECT,B15T7,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 230 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6053 | 6053 | 6053 | HRDB11B13 | HRDTS | DISCONNECT,B11B13,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 231 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6546 | 6546 | 6546 | HRDB12L18-2 | HRDTS | DISCONNECT,B12L18-2,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 232 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 275789 | 275789 | 275789 | HRDB12L42-1 | HRDTS | DISCONNECTS B12L42-1,HRD TS | 230 KV MOTOR OPERATED HV SWITCH (MOD) | 233 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6031 | 6031 | 6031 | HRDB8T6 | HRDTS | DISCONNECT,B8T6,HRD TS | 138 KV MOTOR OPERATED HV SWITCH (MOD) | 235 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6032 | 6032 | 6032 | HRDB8T7 | HRDTS | DISCONNECT,B8T7,HRD TS | 138 KV MOTOR OPERATED HV SWITCH (MOD) | 236 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6033 | 6033 | 6033 | HRDB8T8 | HRDTS | DISCONNECT,B8T8,HRD TS | 138 KV MOTOR OPERATED HV SWITCH (MOD) | 237 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6040 | 6040 | 6040 | HRDB8L39-2 | HRDTS | DISCONNECT,B8L39-2,HRD TS | 138 KV MOTOR OPERATED HV SWITCH (MOD) | 238 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6041 | 6041 | 6041 | HRDB8L39-1 | HRDTS | DISCONNECT,B8L39-1,HRD TS | 138 KV MOTOR OPERATED HV SWITCH (MOD) | 239 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6042 | 6042 | 6042 | HRDB7T5-2 | HRDTS | DISCONNECT,B7T5-2,HRD TS | 66 KV MANUAL OPERATED HV SWITCH | 243 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6043 | 6043 | 6043 | HRDL2L38 | HRDTS | DISCONNECT,L2L38,HRD TS | 67 KV MANUAL OPERATED HV SWITCH | 244 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6044 | 6044 | 6044 | HRDB7L38-1 | HRDTS | DISCONNECT,B7L38-1,HRD TS | 68 KV MANUAL OPERATED HV SWITCH | 245 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |

Table 11-2 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6045 | 6045 | 6045 | HRDB7L38-2 | HRDTS | DISCONNECT,B7L38-2,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 246 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6046 | 6046 | 6046 | HRDB7L2-2 | HRDTS | DISCONNECT,B7L2-2,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 247 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6047 | 6047 | 6047 | HRDB7L2-1 | HRDTS | DISCONNECT,B7L2-1,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 248 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6048 | 6048 | 6048 | HRDB6L3-1 | HRDTS | DISCONNECT,B6L3-1,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 249 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6049 | 6049 | 6049 | HRDB6L3-2 | HRDTS | DISCONNECT,B6L3-2,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 250 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6050 | 6050 | 6050 | HRDB6B7 | HRDTS | DISCONNECT,B6B7,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 251 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6051 | 6051 | 6051 | HRDB7T5-1 | HRDTS | DISCONNECT,B7T5-1,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 252 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |
| 1325 | 6052 | 6052 | 6052 | HRDB6T10-1 | HRDTS | DISCONNECT,B6T10-1,HRD TS | 69 KV MANUAL OPERATED HV SWITCH | 253 | 7 | Develop programs for overhauling, retrofitting, modifications, spares and support to extend life to 2041. (Implementation as per Table 11-5, Section 11.1.1.9) | 2012 | 1 |

Notes:

1. The intent is to develop a life plan for the switchyard breakers and switches in 2012 for implementation (per Table 11-5) starting in or about 2015 to 2020.

### 11.1.1.5 Risk Assessment

The risk assessment associated with the switchyard switchgear, both from a technological perspective and a safety perspective, is illustrated below in Table 11-3.

**TABLE 11-3 RISK ASSESSMENT – SWITCHYARD SWITCHGEAR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | None | 185 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path generation to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5991 | 5991 | 310-77-3 | | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | None | 186 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5992 | 5992 | 460-80 AD/2 | | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | None | 187 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 11 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5993 | 5993 | 310-77-2 | | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | None | 188 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5994 | 5994 | 170-73-3 | | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | None | 189 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 3 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5995 | 5995 | 310-77-4 | | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | None | 190 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5996 | 5996 | 188-74-2 | | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | None | 191 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 6 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 ring bus connection Bus B2 from unit 2 generator to Bus B11 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5997 | 5997 | 188-74-1 | | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | None | 192 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 4 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 ring bus connection Bus B1 from unit 1 generator to Bus B11 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5998 | 5998 | 170-73-2 | | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | None | 193 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 7 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5999 | 5999 | 170-73-1 | | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | None | 194 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 7 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6000 | 6000 | 0464DT72 | | HRDTS | BREAKER,B6T10,HRD TS | 69 KV | None | 195 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 26 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus B6 to transformer T10 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6001 | 6001 | 90/K31238935 | | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | None | 196 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 20 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus B12 to transformer T10 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6002 | 6002 | 45510DD/1 | | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | None | 197 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 11 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6003 | 6003 | 0465DT72 | | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | None | 198 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 26 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection from Transformer T5 to Bus 7 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6004 | 6004 | 61130 | | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | None | 199 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus B7 to Bus 2 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6005 | 6005 | 63257 | | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | None | 200 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | D | High | 2 | C | Medium | Loss of feed to Line 39L to Whitbourne | Test, maintain. refurbish. |
| 1325 | 6006 | 6006 | 64018 | | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | None | 201 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 8 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus B6 to Line 3 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6007 | 6007 | 61131 | | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | None | 202 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus B7 to Line 38 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6008 | 6008 | 991110 | | HRDTS | DISCONNECT,B12L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 206 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6009 | 6009 | 991110 | | HRDTS | DISCONNECT,B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 207 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6010 | 6010 | 991110 | | HRDTS | DISCONNECT,B2L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 208 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6011 | 6011 | 991110 | | HRDTS | DISCONNECT,B2B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 209 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 2 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6012 | 6012 | 991110 | | HRDTS | DISCONNECT,B2B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 210 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 2 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6013 | 6013 | 991110 | | HRDTS | DISCONNECT,B12L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 211 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |

Table 11-3 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6014 | 6014 | 991110 | | HRDTS | DISCONNECT,B2L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 212 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6015 | 6015 | 991110 | | HRDTS | DISCONNECT,B1L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 213 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6016 | 6016 | 991110 | | HRDTS | DISCONNECT,B12L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 214 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6017 | 6017 | 991110 | | HRDTS | DISCONNECT,B1L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 215 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL217 Western Avalon | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6018 | 6018 | 991110 | | HRDTS | DISCONNECT,B1B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 216 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 1 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6019 | 6019 | 991110 | | HRDTS | DISCONNECT,B12T10-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 217 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6020 | 6020 | 991110 | | HRDTS | DISCONNECT,B12L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 218 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6021 | 6021 | 991110 | | HRDTS | DISCONNECT,B12B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 219 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to Bus 15 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6022 | 6022 | 991110 | | HRDTS | DISCONNECT,B13B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 220 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to Bus 15 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6023 | 6023 | 991110 | | HRDTS | DISCONNECT,B3L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 221 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6024 | 6024 | 991110 | | HRDTS | DISCONNECT,B3L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 222 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6025 | 6025 | 991110 | | HRDTS | DISCONNECT,B3B13-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 223 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 3 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6026 | 6026 | 991110 | | HRDTS | DISCONNECT,B3B13-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 224 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 3 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6027 | 6027 | 991110 | | HRDTS | DISCONNECT,B13B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 225 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to Bus 15 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6028 | 6028 | 991110 | | HRDTS | DISCONNECT,B12B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 226 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to Bus 15 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6029 | 6029 | 991110 | | HRDTS | DISCONNECT,B1B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 227 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path Unit 1 generator to ring bus | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6030 | 6030 | 991110 | | HRDTS | DISCONNECT,B11T5,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 228 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer T5to Bus 11 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6034 | 6034 | 991110 | | HRDTS | DISCONNECT,B15T6,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 229 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6035 | 6035 | 991110 | | HRDTS | DISCONNECT,B3T3,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 230 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss of connection from Unit 3 generator - Loss of one unit. | Test, maintain. refurbish. |
| 1325 | 6036 | 6036 | 991110 | | HRDTS | DISCONNECT,B15T8,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 231 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6037 | 6037 | 991110 | | HRDTS | DISCONNECT,B2T2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 232 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss of connection from Unit 2 generator - Loss of one unit. | Test, maintain. refurbish. |
| 1325 | 6038 | 6038 | 991110 | | HRDTS | DISCONNECT,B1T1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 233 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss of connection from Unit 1 generator - Loss of one unit. | Test, maintain. refurbish. |
| 1325 | 6039 | 6039 | 991110 | | HRDTS | DISCONNECT,B15T7,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 234 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 of 3 connection paths Bus 15 to Bus 8 and load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6053 | 6053 | 991110 | | HRDTS | DISCONNECT,B11B13,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 235 | 7 | Mechanical/electrical failure - system, stn, amb induced. | | N/A | 2 | C | Medium | 2 | C | Medium | Loss of 1 internal ring bus connection | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6546 | 6546 | 991110 | | HRDTS | DISCONNECT,B12L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 236 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL218 Oxen Pond | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 275789 | 275789 | 991110 | | HRDTS | DISCONNECTS B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 237 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 connection path ring bus to load TL242 Hardwoods | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6031 | 6031 | 991110 | | HRDTS | DISCONNECT,B8T6,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 238 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 of 3 connection path transformer 6 to Bus 8 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6032 | 6032 | 991110 | | HRDTS | DISCONNECT,B8T7,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 239 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 of 3 connection path transformer 7 to Bus 8 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6033 | 6033 | 991110 | | HRDTS | DISCONNECT,B8T8,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 240 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss 1 of 3 connection path transformer 8 to Bus 8 to load 39L Whitborne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6040 | 6040 | 991110 | | HRDTS | DISCONNECT,B8L39-2,HRD TS | 138 KV | Manual Operated HV Switch | 241 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss connection path Bus 8 to load 39L Whitborne | Test, maintain. refurbish. |
| 1325 | 6041 | 6041 | 991110 | | HRDTS | DISCONNECT,B8L39-1,HRD TS | 138 KV | Manual Operated HV Switch | 242 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | D | High | 2 | C | Medium | Loss connection path Bus 8 to load 39L Whitborne | Test, maintain. refurbish. |

Table 11-3 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6042 | 6042 | 991110 | | HRDTS | DISCONNECT,B7T5-2,HRD TS | 69 KV | Manual Operated HV Switch | 245 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection to Bus 7 from transformer T5 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6043 | 6043 | 991110 | | HRDTS | DISCONNECT,L2L38,HRD TS | 69 KV | Manual Operated HV Switch | 246 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformerline L2 to L38 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6044 | 6044 | 991110 | | HRDTS | DISCONNECT,B7L38-1,HRD TS | 69 KV | Manual Operated HV Switch | 247 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer Bus 7 to line 38 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6045 | 6045 | 991110 | | HRDTS | DISCONNECT,B7L38-2,HRD TS | 69 KV | Manual Operated HV Switch | 248 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer Bus 7 to line 38 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6046 | 6046 | 991110 | | HRDTS | DISCONNECT,B7L2-2,HRD TS | 69 KV | Manual Operated HV Switch | 249 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer Bus 7 to line 2 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6047 | 6047 | 991110 | | HRDTS | DISCONNECT,B7L2-1,HRD TS | 69 KV | Manual Operated HV Switch | 250 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6048 | 6048 | 991110 | | HRDTS | DISCONNECT,B6L3-1,HRD TS | 69 KV | Manual Operated HV Switch | 251 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer Bus 6 to Line 3 - 69 kV to SB34 Interconnection | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6049 | 6049 | 991110 | | HRDTS | DISCONNECT,B6L3-2,HRD TS | 69 KV | Manual Operated HV Switch | 252 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus 6 to Line 3 - Inter-unit connection to Station Board 34-69 kV | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6050 | 6050 | 991110 | | HRDTS | DISCONNECT,B6B7,HRD TS | 69 KV | Manual Operated HV Switch | 253 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection Bus 6 to Bus 7 - Inter-unit connection - 69 kV to Units 1&2 loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6051 | 6051 | 991110 | | HRDTS | DISCONNECT,B7T5-1,HRD TS | 69 KV | Manual Operated HV Switch | 254 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer T5 to Bus 7 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 6052 | 6052 | 991110 | | HRDTS | DISCONNECT,B6T10-1,HRD TS | 69 KV | Manual Operated HV Switch | 255 | 7 | Mechanical/electrical failure - system, stn, amb induced. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Loss of connection transformer T10 to Bus 6 - 69 kV loads and Seal Point | Parallel paths (existing). Test, maintain. refurbish. |

Notes:

1. In most cases, the electrical connections associated with breakers and switches have been paralleled to reduce risk of unit loss or loss of generation supply to loads.

2. Compressor air line information is premised on completion of replacement in 2010/11. Otherwise risk level would be "High".

### 11.1.1.6 Life Cycle Curve and Remaining Life

The life cycle curves for the switchyard equipment (excluding transformers) are illustrated in the two figures below. The first represents the breakers and the second is for the motorized disconnects and switches. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of the estimated current and projected numbers of operation on the y-axis versus calendar year on the x-axis. The numbers of operation is an estimate by AMEC based on unit starts and stops and not on actual values for which there was no data available. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

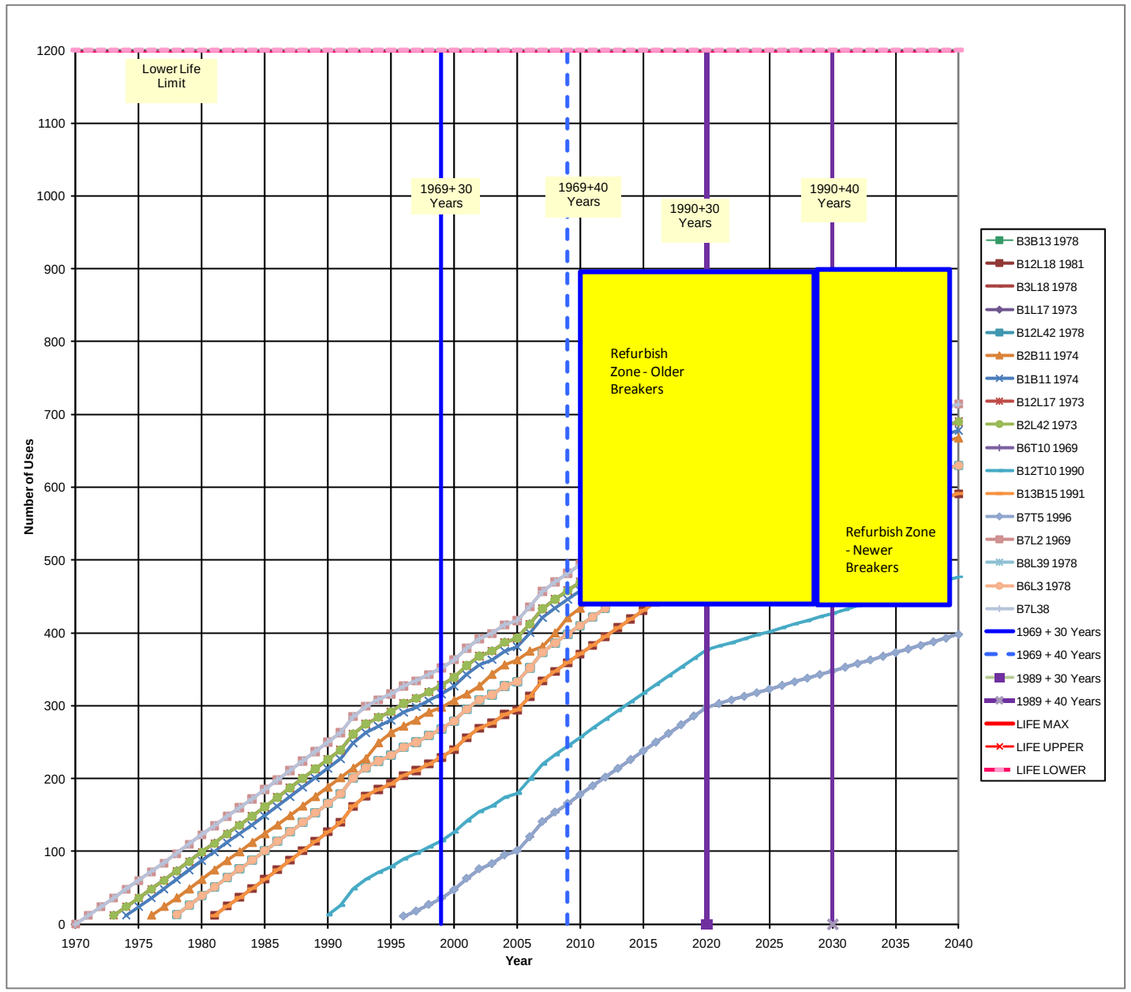



**FIGURE 11-2 LIFE CYCLE CURVE – SWITCHYARD SWITCHGEAR - BREAKERS**

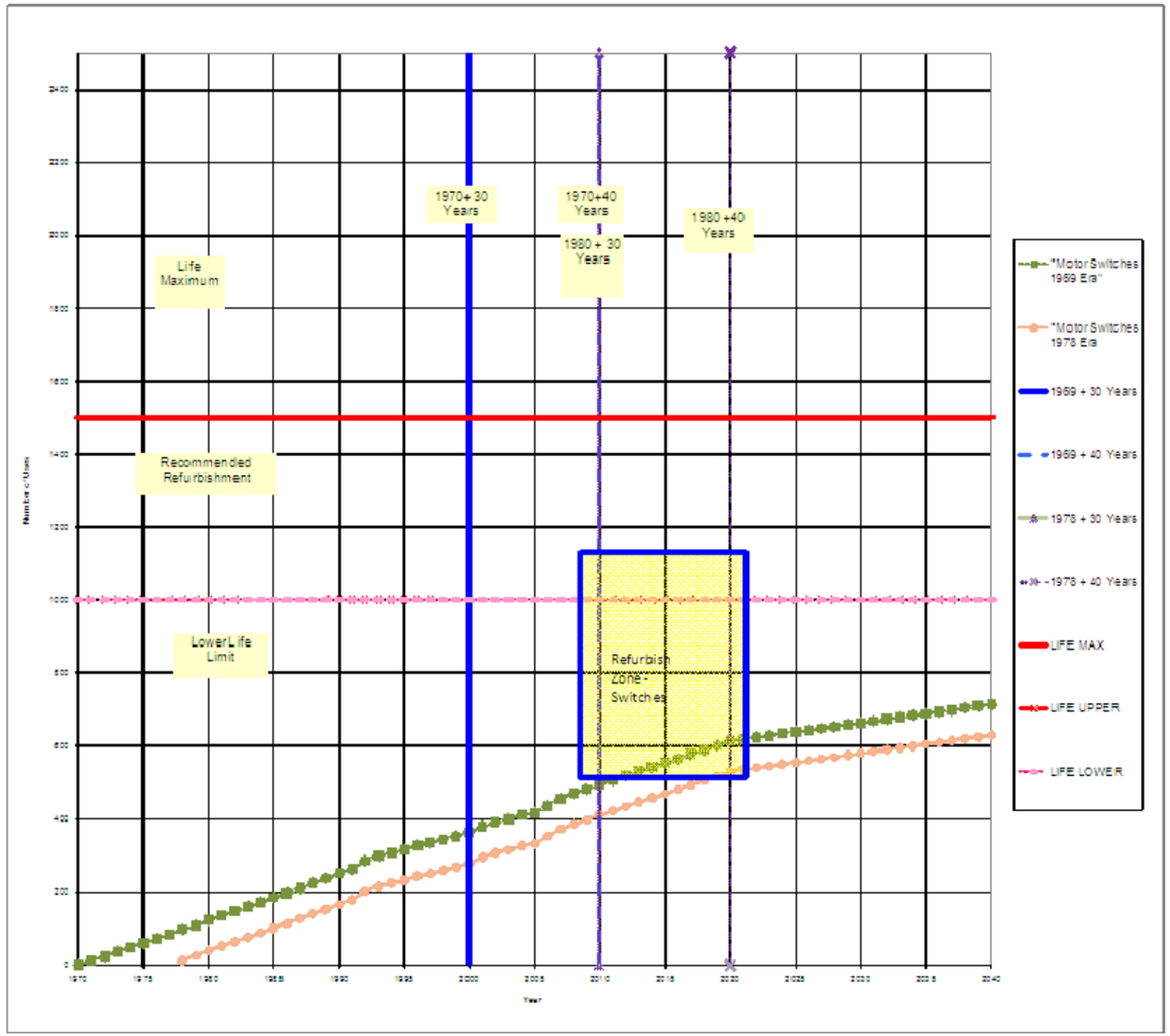



**FIGURE 11-3 LIFE CYCLE CURVE – SWITCHYARD SWITCHGEAR - MOTORIZED DISCONNECTS AND SWITCHES**

The curves indicate that the remaining life (RL) of the switchyard switchgear exceeds the end date for generation of 2020, but not the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The equipment has reached an age where reliability is a concern, particularly where system interruptions or lightning storm impacts play a role. Given the critical nature of the station and its switchyard to the supply of the mainland, a pro-active program of testing and refurbishment is a priority.

### 11.1.1.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-4 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-4 LEVEL 2 INSPECTION – SWITCHYARD SWITCHGEAR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | N/A | 162 | 7 | No Level 2 required. | | | |
| 1325 | 5991 | 5991 | 310-77-3 | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | N/A | 163 | 7 | No Level 2 required. | | | |
| 1325 | 5992 | 5992 | 460-80 AD/2 | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | N/A | 164 | 7 | No Level 2 required. | | | |
| 1325 | 5993 | 5993 | 310-77-2 | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | N/A | 165 | 7 | No Level 2 required. | | | |
| 1325 | 5994 | 5994 | 170-73-3 | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | N/A | 166 | 7 | No Level 2 required. | | | |
| 1325 | 5995 | 5995 | 310-77-4 | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | N/A | 167 | 7 | No Level 2 required. | | | |
| 1325 | 5996 | 5996 | 188-74-2 | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | N/A | 168 | 7 | No Level 2 required. | | | |
| 1325 | 5997 | 5997 | 188-74-1 | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | N/A | 169 | 7 | No Level 2 required. | | | |
| 1325 | 5998 | 5998 | 170-73-2 | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | N/A | 170 | 7 | No Level 2 required. | | | |
| 1325 | 5999 | 5999 | 170-73-1 | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | N/A | 171 | 7 | No Level 2 required. | | | |
| 1325 | 6000 | 6000 | 0464DT72 | HRDTS | BREAKER,B6T10,HRD TS | 69 KV | N/A | 172 | 7 | No Level 2 required. | | | |
| 1325 | 6001 | 6001 | 90/K31238935 | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | N/A | 173 | 7 | No Level 2 required. | | | |
| 1325 | 6002 | 6002 | 45510DD/1 | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | N/A | 174 | 7 | No Level 2 required. | | | |
| 1325 | 6003 | 6003 | 0465DT72 | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | N/A | 175 | 7 | No Level 2 required. | | | |
| 1325 | 6004 | 6004 | 61130 | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | N/A | 176 | 7 | No Level 2 required. | | | |
| 1325 | 6005 | 6005 | 63257 | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | N/A | 177 | 7 | No Level 2 required. | | | |
| 1325 | 6006 | 6006 | 64018 | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | N/A | 178 | 7 | No Level 2 required. | | | |
| 1325 | 6007 | 6007 | 61131 | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | N/A | 179 | 7 | No Level 2 required. | | | |

Table 11-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6008 | 6008 | 6008 | HRDTS | DISCONNECT,B12L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 183 | 7 | No Level 2 required. | | | |
| 1325 | 6009 | 6009 | 6009 | HRDTS | DISCONNECT,B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 184 | 7 | No Level 2 required. | | | |
| 1325 | 6010 | 6010 | 6010 | HRDTS | DISCONNECT,B2L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 185 | 7 | No Level 2 required. | | | |
| 1325 | 6011 | 6011 | 6011 | HRDTS | DISCONNECT,B2B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 186 | 7 | No Level 2 required. | | | |
| 1325 | 6012 | 6012 | 6012 | HRDTS | DISCONNECT,B2B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 187 | 7 | No Level 2 required. | | | |
| 1325 | 6013 | 6013 | 6013 | HRDTS | DISCONNECT,B12L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 188 | 7 | No Level 2 required. | | | |
| 1325 | 6014 | 6014 | 6014 | HRDTS | DISCONNECT,B2L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 189 | 7 | No Level 2 required. | | | |
| 1325 | 6015 | 6015 | 6015 | HRDTS | DISCONNECT,B1L17-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 190 | 7 | No Level 2 required. | | | |
| 1325 | 6016 | 6016 | 6016 | HRDTS | DISCONNECT,B12L42-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 191 | 7 | No Level 2 required. | | | |
| 1325 | 6017 | 6017 | 6017 | HRDTS | DISCONNECT,B1L17-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 192 | 7 | No Level 2 required. | | | |
| 1325 | 6018 | 6018 | 6018 | HRDTS | DISCONNECT,B1B11-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 193 | 7 | No Level 2 required. | | | |
| 1325 | 6019 | 6019 | 6019 | HRDTS | DISCONNECT,B12T10-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 194 | 7 | No Level 2 required. | | | |
| 1325 | 6020 | 6020 | 6020 | HRDTS | DISCONNECT,B12L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 195 | 7 | No Level 2 required. | | | |
| 1325 | 6021 | 6021 | 6021 | HRDTS | DISCONNECT,B12B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 196 | 7 | No Level 2 required. | | | |
| 1325 | 6022 | 6022 | 6022 | HRDTS | DISCONNECT,B13B15-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 197 | 7 | No Level 2 required. | | | |
| 1325 | 6023 | 6023 | 6023 | HRDTS | DISCONNECT,B3L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 198 | 7 | No Level 2 required. | | | |
| 1325 | 6024 | 6024 | 6024 | HRDTS | DISCONNECT,B3L18-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 199 | 7 | No Level 2 required. | | | |
| 1325 | 6025 | 6025 | 6025 | HRDTS | DISCONNECT,B3B13-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 200 | 7 | No Level 2 required. | | | |
| 1325 | 6026 | 6026 | 6026 | HRDTS | DISCONNECT,B3B13-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 201 | 7 | No Level 2 required. | | | |

Table 11-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6027 | 6027 | 6027 | HRDTS | DISCONNECT,B13B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 202 | 7 | No Level 2 required. | | | |
| 1325 | 6028 | 6028 | 6028 | HRDTS | DISCONNECT,B12B15-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 203 | 7 | No Level 2 required. | | | |
| 1325 | 6029 | 6029 | 6029 | HRDTS | DISCONNECT,B1B11-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 204 | 7 | No Level 2 required. | | | |
| 1325 | 6030 | 6030 | 6030 | HRDTS | DISCONNECT,B11T5,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 205 | 7 | No Level 2 required. | | | |
| 1325 | 6034 | 6034 | 6034 | HRDTS | DISCONNECT,B15T6,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 206 | 7 | No Level 2 required. | | | |
| 1325 | 6035 | 6035 | 6035 | HRDTS | DISCONNECT,B3T3,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 207 | 7 | No Level 2 required. | | | |
| 1325 | 6036 | 6036 | 6036 | HRDTS | DISCONNECT,B15T8,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 208 | 7 | No Level 2 required. | | | |
| 1325 | 6037 | 6037 | 6037 | HRDTS | DISCONNECT,B2T2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 209 | 7 | No Level 2 required. | | | |
| 1325 | 6038 | 6038 | 6038 | HRDTS | DISCONNECT,B1T1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 210 | 7 | No Level 2 required. | | | |
| 1325 | 6039 | 6039 | 6039 | HRDTS | DISCONNECT,B15T7,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 211 | 7 | No Level 2 required. | | | |
| 1325 | 6053 | 6053 | 6053 | HRDTS | DISCONNECT,B11B13,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 212 | 7 | No Level 2 required. | | | |
| 1325 | 6546 | 6546 | 6546 | HRDTS | DISCONNECT,B12L18-2,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 213 | 7 | No Level 2 required. | | | |
| 1325 | 275789 | 275789 | 275789 | HRDTS | DISCONNECTS B12L42-1,HRD TS | 230 KV | Motor Operated HV Switch (MOD) | 214 | 7 | No Level 2 required. | | | |
| 1325 | 6031 | 6031 | 6031 | HRDTS | DISCONNECT,B8T6,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 215 | 7 | No Level 2 required. | | | |
| 1325 | 6032 | 6032 | 6032 | HRDTS | DISCONNECT,B8T7,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 216 | 7 | No Level 2 required. | | | |
| 1325 | 6033 | 6033 | 6033 | HRDTS | DISCONNECT,B8T8,HRD TS | 138 KV | Motor Operated HV Switch (MOD) | 217 | 7 | No Level 2 required. | | | |
| 1325 | 6040 | 6040 | 6040 | HRDTS | DISCONNECT,B8L39-2,HRD TS | 138 KV | Manual Operated HV Switch | 220 | 7 | No Level 2 required. | | | |
| 1325 | 6041 | 6041 | 6041 | HRDTS | DISCONNECT,B8L39-1,HRD TS | 138 KV | Manual Operated HV Switch | 221 | 7 | No Level 2 required. | | | |
| 1325 | 6042 | 6042 | 6042 | HRDTS | DISCONNECT,B7T5-2,HRD TS | 69 KV | Manual Operated HV Switch | 222 | 7 | No Level 2 required. | | | |
| 1325 | 6043 | 6043 | 6043 | HRDTS | DISCONNECT,L2L38,HRD TS | 69 KV | Manual Operated HV Switch | 223 | 7 | No Level 2 required. | | | |

Table 11-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6044 | 6044 | 6044 | HRDTS | DISCONNECT,B7L38-1,HRD TS | 69 KV | Manual Operated HV Switch | 224 | 7 | No Level 2 required. | | | |
| 1325 | 6045 | 6045 | 6045 | HRDTS | DISCONNECT,B7L38-2,HRD TS | 69 KV | Manual Operated HV Switch | 225 | 7 | No Level 2 required. | | | |
| 1325 | 6046 | 6046 | 6046 | HRDTS | DISCONNECT,B7L2-2,HRD TS | 69 KV | Manual Operated HV Switch | 226 | 7 | No Level 2 required. | | | |
| 1325 | 6047 | 6047 | 6047 | HRDTS | DISCONNECT,B7L2-1,HRD TS | 69 KV | Manual Operated HV Switch | 227 | 7 | No Level 2 required. | | | |
| 1325 | 6048 | 6048 | 6048 | HRDTS | DISCONNECT,B6L3-1,HRD TS | 69 KV | Manual Operated HV Switch | 228 | 7 | No Level 2 required. | | | |
| 1325 | 6049 | 6049 | 6049 | HRDTS | DISCONNECT,B6L3-2,HRD TS | 69 KV | Manual Operated HV Switch | 229 | 7 | No Level 2 required. | | | |
| 1325 | 6050 | 6050 | 6050 | HRDTS | DISCONNECT,B6B7,HRD TS | 69 KV | Manual Operated HV Switch | 230 | 7 | No Level 2 required. | | | |
| 1325 | 6051 | 6051 | 6051 | HRDTS | DISCONNECT,B7T5-1,HRD TS | 69 KV | Manual Operated HV Switch | 231 | 7 | No Level 2 required. | | | |
| 1325 | 6052 | 6052 | 6052 | HRDTS | DISCONNECT,B6T10-1,HRD TS | 69 KV | Manual Operated HV Switch | 232 | 7 | No Level 2 required. | | | |

### 11.1.1.8 Capital Projects

The suggested typical capital enhancements for the switchyard switchgear include:

**TABLE 11-5 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – SWITCHYARD SWITCHGEAR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | HRDB3B13 | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | 168 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5991 | 5991 | 310-77-3 | HRDB12B15 | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | 169 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5992 | 5992 | 460-80 AD/2 | HRDB12L18 | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | 170 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5993 | 5993 | 310-77-2 | HRDB3L18 | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | 171 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5994 | 5994 | 170-73-3 | HRDB1L17 | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | 172 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5995 | 5995 | 310-77-4 | HRDB12L42 | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | 173 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5996 | 5996 | 188-74-2 | HRDB2B11 | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | 174 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5997 | 5997 | 188-74-1 | HRDB1B11 | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | 175 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5998 | 5998 | 170-73-2 | HRDB12L17 | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | 176 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5999 | 5999 | 170-73-1 | HRDB2L42 | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | 177 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6000 | 6000 | 0464DT72 | HRDB6T10 | HRDTS | BREAKER,B6T10,HRD TS | 69 KV | 178 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6001 | 6001 | 90/K31238935 | HRDB12T10 | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | 179 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6002 | 6002 | 45510DD/1 | HRDB13B15 | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | 180 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6003 | 6003 | 0465DT72 | HRDB7T5 | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | 181 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6004 | 6004 | 61130 | HRDB7L2 | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | 182 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6005 | 6005 | 63257 | HRDB8L39 | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | 183 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6006 | 6006 | 64018 | HRDB6L3 | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | 184 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6007 | 6007 | 61131 | HRDB7L38 | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | 185 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

Table 11-5 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6008 | 6008 | 6008 | HRDB12L17-1 | HRDTS | DISCONNECT,B12L17-1,HRD TS | 230 KV | 189 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6009 | 6009 | 6009 | HRDB12L42-1 | HRDTS | DISCONNECT,B12L42-1,HRD TS | 230 KV | 190 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6010 | 6010 | 6010 | HRDB2L42-1 | HRDTS | DISCONNECT,B2L42-1,HRD TS | 230 KV | 191 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6011 | 6011 | 6011 | HRDB2B11-1 | HRDTS | DISCONNECT,B2B11-1,HRD TS | 230 KV | 192 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6012 | 6012 | 6012 | HRDB2B11-2 | HRDTS | DISCONNECT,B2B11-2,HRD TS | 230 KV | 193 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6013 | 6013 | 6013 | HRDB12L17-2 | HRDTS | DISCONNECT,B12L17-2,HRD TS | 230 KV | 194 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6014 | 6014 | 6014 | HRDB2L42-2 | HRDTS | DISCONNECT,B2L42-2,HRD TS | 230 KV | 195 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6015 | 6015 | 6015 | HRDB1L17-2 | HRDTS | DISCONNECT,B1L17-2,HRD TS | 230 KV | 196 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6016 | 6016 | 6016 | HRDB12L42-2 | HRDTS | DISCONNECT,B12L42-2,HRD TS | 230 KV | 197 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6017 | 6017 | 6017 | HRDB1L17-1 | HRDTS | DISCONNECT,B1L17-1,HRD TS | 230 KV | 198 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6018 | 6018 | 6018 | HRDB1B11-1 | HRDTS | DISCONNECT,B1B11-1,HRD TS | 230 KV | 199 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6019 | 6019 | 6019 | HRDB12T10-1 | HRDTS | DISCONNECT,B12T10-1,HRD TS | 230 KV | 200 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6020 | 6020 | 6020 | HRDB12L18-1 | HRDTS | DISCONNECT,B12L18-1,HRD TS | 230 KV | 201 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6021 | 6021 | 6021 | HRDB12B15-2 | HRDTS | DISCONNECT,B12B15-2,HRD TS | 230 KV | 202 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6022 | 6022 | 6022 | HRDB13B15-2 | HRDTS | DISCONNECT,B13B15-2,HRD TS | 230 KV | 203 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6023 | 6023 | 6023 | HRDB3L18-2 | HRDTS | DISCONNECT,B3L18-2,HRD TS | 230 KV | 204 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6024 | 6024 | 6024 | HRDB3L18-1 | HRDTS | DISCONNECT,B3L18-1,HRD TS | 230 KV | 205 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6025 | 6025 | 6025 | HRDB3B13-1 | HRDTS | DISCONNECT,B3B13-1,HRD TS | 230 KV | 206 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6026 | 6026 | 6026 | HRDB3B13-2 | HRDTS | DISCONNECT,B3B13-2,HRD TS | 230 KV | 207 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6027 | 6027 | 6027 | HRDB13B15-1 | HRDTS | DISCONNECT,B13B15-1,HRD TS | 230 KV | 208 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6028 | 6028 | 6028 | HRDB12B15-1 | HRDTS | DISCONNECT,B12B15-1,HRD TS | 230 KV | 209 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6029 | 6029 | 6029 | HRDB1B11-2 | HRDTS | DISCONNECT,B1B11-2,HRD TS | 230 KV | 210 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6030 | 6030 | 6030 | HRDB11T5 | HRDTS | DISCONNECT,B11T5,HRD TS | 230 KV | 211 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6034 | 6034 | 6034 | HRDB15T6 | HRDTS | DISCONNECT,B15T6,HRD TS | 230 KV | 212 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6035 | 6035 | 6035 | HRDB3T3 | HRDTS | DISCONNECT,B3T3,HRD TS | 230 KV | 213 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

Table 11-5 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6036 | 6036 | 6036 | HRDB15T8 | HRDTS | DISCONNECT,B15T8,HRD TS | 230 KV | 214 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6037 | 6037 | 6037 | HRDB2T2 | HRDTS | DISCONNECT,B2T2,HRD TS | 230 KV | 215 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6038 | 6038 | 6038 | HRDB1T1 | HRDTS | DISCONNECT,B1T1,HRD TS | 230 KV | 216 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6039 | 6039 | 6039 | HRDB15T7 | HRDTS | DISCONNECT,B15T7,HRD TS | 230 KV | 217 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6053 | 6053 | 6053 | HRDB11B13 | HRDTS | DISCONNECT,B11B13,HRD TS | 230 KV | 218 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6546 | 6546 | 6546 | HRDB12L18-2 | HRDTS | DISCONNECT,B12L18-2,HRD TS | 230 KV | 219 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 275789 | 275789 | 275789 | HRDB12L42-1 | HRDTS | DISCONNECTS B12L42-1,HRD TS | 230 KV | 220 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6031 | 6031 | 6031 | HRDB8T6 | HRDTS | DISCONNECT,B8T6,HRD TS | 138 KV | 221 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6032 | 6032 | 6032 | HRDB8T7 | HRDTS | DISCONNECT,B8T7,HRD TS | 138 KV | 222 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6033 | 6033 | 6033 | HRDB8T8 | HRDTS | DISCONNECT,B8T8,HRD TS | 138 KV | 223 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6040 | 6040 | 6040 | HRDB8L39-2 | HRDTS | DISCONNECT,B8L39-2,HRD TS | 138 KV | 224 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6041 | 6041 | 6041 | HRDB8L39-1 | HRDTS | DISCONNECT,B8L39-1,HRD TS | 138 KV | 225 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6042 | 6042 | 6042 | HRDB7T5-2 | HRDTS | DISCONNECT,B7T5-2,HRD TS | 69 KV | 228 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6043 | 6043 | 6043 | HRDL2L38 | HRDTS | DISCONNECT,L2L38,HRD TS | 69 KV | 229 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6044 | 6044 | 6044 | HRDB7L38-1 | HRDTS | DISCONNECT,B7L38-1,HRD TS | 69 KV | 230 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6045 | 6045 | 6045 | HRDB7L38-2 | HRDTS | DISCONNECT,B7L38-2,HRD TS | 69 KV | 231 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6046 | 6046 | 6046 | HRDB7L2-2 | HRDTS | DISCONNECT,B7L2-2,HRD TS | 69 KV | 232 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6047 | 6047 | 6047 | HRDB7L2-1 | HRDTS | DISCONNECT,B7L2-1,HRD TS | 69 KV | 233 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6048 | 6048 | 6048 | HRDB6L3-1 | HRDTS | DISCONNECT,B6L3-1,HRD TS | 69 KV | 234 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6049 | 6049 | 6049 | HRDB6L3-2 | HRDTS | DISCONNECT,B6L3-2,HRD TS | 69 KV | 235 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6050 | 6050 | 6050 | HRDB6B7 | HRDTS | DISCONNECT,B6B7,HRD TS | 69 KV | 236 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6051 | 6051 | 6051 | HRDB7T5-1 | HRDTS | DISCONNECT,B7T5-1,HRD TS | 69 KV | 237 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6052 | 6052 | 6052 | HRDB6T10-1 | HRDTS | DISCONNECT,B6T10-1,HRD TS | 69 KV | 238 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

### 11.1.2 Asset 1325: 5975 to 5989 – Transformers

(Detailed Technical Assessment in Working Papers, Appendix 5)

| | |
|---|---|
| Unit #: | 1,2,3, Common, Holyrood Switchyard |
| Asset Class # | BU 1296 – Assets Generation<br>BU 1297 – Assets Commons<br>BU 1325 – Assets Holyrood Switchyard |
| Components: | BU1325 5975 Unit 1 T1 Power Transformer<br>BU1325 5976 Unit 2 T2 Power Transformer<br>BU1325 5977 Unit 3 T3 Power Transformer<br>BU1325 5978 Transformer T4 (spare)<br>BU1325 5979 Transformer T5<br>BU1325 5980 Transformer T6<br>BU1325 5981 Transformer T7<br>BU1325 5982 Transformer T8<br>BU1325 5983 Transformer T9<br>BU1325 5984 Transformer T10<br>BU1325 6726 Unit 1 Service Power System UST-1 Transformer<br>BU1325 8156 Unit 2 Service Power System UST-2 Transformer<br>BU1325 8716 Unit 3 Unit Service Power System UST-3 Transformer<br>BU1325 6727 Common Stage 1 Station Service Power SST-12 Trans<br>BU1325 5989 Common Stage 2 Station Service Power SST-34 Trans<br>BU 1296 271311 RT1 Unit 1 Rectifying Transformer<br>BU 1296 271324 RT2 Unit 2 Rectifying Transformer<br>BU 1296 271680 RT3 Unit 3 Rectifying Transformer |

There are transformers within the Holyrood plant that are managed by plant operations (the unit rectifying transformers), and transformers outside the plant that are managed by the Transmission and Rural Operations (TRO) group. The requirements for the transformers vary depending on their role, but most will be required to operate until the year 2041. The station has a spare power transformer on site. It was installed as the Unit 2 transformer in 1970, and made the spare as part of the Unit 1 and 2 upgrade to provide some measure of reliability.

| Main Power Transformers | T1<br>Unit 1 | T2<br>Unit 2 | T3<br>Unit 3 |
|---|---|---|---|
| Manufactured/Delivered | 1969 | 1970 | 1979 |
| In-Service Date | Sep 1970 | Apr 1971 | Feb 1980 |
| Replaced | 1987 | 1987 | N/A |
| Generation Peak/Emerg Gen End Date | Dec 2020 | | |
| Synchronous Condensing Start Date | Jan 2015 | Jan 2015 | 1986 |
| Synchronous Condensing End Date | Dec 2041 | Dec 2041 | Dec 2041 |
| Last Major Overhaul/Inspection | See Condition Assessment | | |



FIGURE 11-4 UNIT 1 T1



FIGURE 11-5 UNIT 2 T2



FIGURE 11-6 UNIT 3 T3

#### 11.1.2.1 Description

**Asset 5975 Unit 1 T1 Power Transformer**

The present T1 transformer was manufactured by Trafo-Union, Germany and installed at the T1 location in 1988. It was located originally at the T3 location, being installed there in 1979. It is a 105/140/180 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/OFAF, with tap-changer of +2@4.35%, -1@4.35%, Yd1, Z1=13.6%, Z0=11.7%. T1 transforms the electricity from the Unit 1 generator from 16kV to 230kV.

**Asset 5976 Unit 2 T2 Power Transformer**

The T2 transformer was manufactured by Federal Pioneer and installed in 1989, and is a 115/152/190 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/ONAF, with primary tap-changer of +2@4.35%, -1@4.35%, Yd1, Z1=13.7%, Z0=11.75%. This transformer was a replacement for the original T2 transformer that had been installed in 1970. This original 170 MVA T2 transformer is now designated as T4 and is kept as a spare. T2 transforms the electricity from the Unit 2 generator from 16kV to 230kV.

**Asset 5977 Unit 3 T3 Power Transformer**

The present T3 transformer was manufactured by General Electric and installed at the T3 location in 1978. It was located originally at the T1 location, being installed there in 1970. It is a 170 MVA, Star-Delta, 230kV:16kV, OFAF, +2@4.35%, -1@4.35%, Yd1, Z1=13.5%. T3 transforms the electricity from the Unit 3 generator from 16kV to 230kV.

**Asset 5978 Transformer T4 (spare)**

The present T4 (spare) transformer was manufactured by Canadian General Electric and installed in its current location in 1988. It was located originally at the T2 location, being installed there in 1970. It is a 115/152/170 MVA, Delta-Wye, 230kV:16kV, oil cooled. It can replace T1, T2, or T3, provided the output is limited to 170 MVA.

**Asset 5979 Transformer T5**

T5 transformer was manufactured by Westinghouse and installed in 1969. It is a 15/20/25 MVA, Delta-Wye, 230kV:69kV, oil cooled. It is located between Bus 7 and Bus 11, providing 69kV power, along with T10, to the Station Board SB12 through transformer SST12 and seal core.

**Asset 5980 Transformer T6**

T6 transformer was manufactured by Canadian General Electric in 1960. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=7.5%. Along with T7 and T8, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

**Asset 5981 Transformer T7**

T7 transformer was manufactured by Canadian General Electric pre 1974. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=7.5%. Along with T6 and T8, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

**Asset 5982 Transformer T8**

T8 transformer was manufactured by Federal Pioneer in 1989. It is a 75/100/125 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, oil cooled. Along with T6 and T7, it is one of three transformers between 230kV Bus 15 and 138KV Bus 8 which supplies power to Line 39L to Whitbourne.

**Asset 5982 Transformer T9**

T9 transformer was manufactured by Federal Pioneer in 1970. It is a 10.5/14 MVA, ONAN/ONAF, Wye-Delta, 13.8kV:4160Y/2400V, resistance grounded, with primary tap-changer of +2@2.5%, -2@2.5%, Dy1, Z1=7.5%. T9 transforms the electricity from the gas turbine generator to the Station Board SB12.

**Asset 5983 Transformer T10**

T10 transformer was manufactured by Federal Pioneer in 1990. It is a 15/20/25 MVA, ONAN/ONAF/ONAF, Wye-Delta, 230kV:69kV. T10 is located between Bus B11 and B6, providing 69kV power, along with T5, to the Station Board SB12 through Transformer SST12 and to seal core.

**Asset 6726 Unit 1 Service Power System, UST-1 Transformer**

The UST-1 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer, +2@2.5%, -2@2.5%, Dy1. UST-1 is located between the Unit 1 generator and the 4160V Unit Board UB1.

**Asset 8156 Unit 2 Service Power System, UST-2 Transformer**

The UST-2 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1. UST-2 is located between the Unit 2 generator and the 4160V Unit Board UB2

**Asset 8716 Unit 3 Unit Service Power System, UST-3 Transformer**

The UST-3 transformer was manufactured by General Electric, installed in 1978 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. UST-3 is located between the Unit 3 generator and the 4160V Unit Board UB3

**Asset 6727 Common Stage 1 Station Service Power. SST-12 Trans**

The SST-12 transformer was manufactured by Federal Pioneer, installed in 1969, and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6.86%. SST12 is located between Bus 2 (which can take power from Bus 6 or Bus 7) and the 4160V Station Board SB12.

**Asset 5989 Common, Stage 2 Station Service Power, SST-34 Trans.**

The SST-34 transformer was manufactured by Westinghouse, installed in 1978 and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. SST34 is located between Bus 3 (which can take power from Bus 6 or Bus 7) and the 4160V Station Board SB34.

**Asset 271311 RT1 Unit 1 Rectifying Transformer**

Rectifying Transformer RT1 was manufactured by CGE, installed in 1969, and is a 2154/1077kVA, LNAN, 16000:750:575 Tertiary, oil filled type. Original Askarel oil was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. RT1 is part of the Unit 1 generator exciter.

**Asset 271324 RT2 Unit 2 Rectifying Transformer**

Rectifying Transformer RT2 was manufactured by CGE, installed in 1969, and is a 2154/1077kVA, LNAN, 16000:750:575 Tertiary, oil filled type. Original Askarel oil was changed in 2004 to Perchloroethylene with below 50mg/kg PCB's. RT2 is part of the Unit 2 generator exciter.

**Asset 271680 RT3 Unit 3 Rectifying Transformer**

Rectifying Transformer RT3 was manufactured by FPE, installed in 1979, and is a 1400 kVA, 16000: 575V, dry type. It is installed as part of Unit 3 exciter system.

#### 11.1.2.2 Inspection and Repair History

The following information covers the transformers outside the building and in the switchyard, and Units 1, 2 and 3 excitation transformers inside the building. Planned maintenance (PM) and corrective action (CA) sheets are available for the transformer equipment.

Scheduled maintenance for the transformer equipment is as follows:

- 6 year detailed Planned Maintenance;
- Thermography tests each year;
- Visual inspections every 4 months; and
- Annual oil sampling.

Transformer insulating oil test results versus the Institute of Electrical and Electronics Engineers (IEEE) recommendations and standards are given for each section. It should be noted that NL Hydro TRO transmission system staff indicated that AMEC used a reference to an IEEE standard with parameters of new oil whereas NL Hydro use an IEEE standard for in service transformer oil (IEEE Standard 637 Guideline which has parameters for Reclaimed Transformer Oil). NL Hydro also uses SD Myers Transformer Maintenance Institute parameters for evaluating oil quality for in service transformer oil. NL Hydro's practice is in fact standard practice within the electric utility sector.

TRO maintains a significant and regularly scheduled transformer maintenance and inspection program. Shifts in document management have made it difficult to find records of the results of all of the work that have been performed in the last five to seven years. Some work on Hydro's standard work sheets has not been completed, for which there may be many valid reasons. Given the age of the equipment, more rigorous testing and monitoring/trending of equipment condition will be necessary. Monitoring and trending of unusual system disturbances or environmental events such as lightning strikes needs more attention.

**Asset 5975 Unit 1 T1 Power Transformer**

Doble tests and PM were completed in 2000 and 2005. Given a six year test cycle, no more recent PM or tests are expected before 2011. Typical maintenance request sheets were reviewed, but not all work was indicated as having been done (for which there can be many valid reasons) Maintenance completed during years 2000 to 2005 included some fan maintenance, various gauge/relay maintenance, and pump maintenance. Silica gel was replaced in 2007. No other maintenance was identified for the period from

2005 to present, except for T1 oil reclamation in 2008, were identified (Closed PM Work Order in 2008 subsequently identified). Transformer maintenance history sheets were available from July 1979 to June 2005. Reference "Significant Work Performed" identified by work orders in JD Edwards (JDE) database for maintenance history.

**Asset 5976 Unit 2 T2 Power Transformer**

Doble tests were completed in 2002, but there was no record available to AMEC of more recent tests that would have been completed in 2008. Maintenance records were reviewed indicating work carried out during years 2000 to 2006, including the fans. No indication of similar maintenance was available for 2007 to present. Silica gel was replaced in 2002 and 2007. T2 had its oil reclaimed in 2008. Six year planned maintenance sheets are originally available for 2009. The last PM date was subsequently identified as 2009, same as oil test date.

**Asset 5977 Unit 3 T3 Power Transformer**

Doble tests were completed in 2002, but there was no record available to AMEC of more recent tests that would have been completed in 2008. Typical maintenance has been recorded as completed during years 2008 and 2009 for various gauge/relay maintenance, pump maintenance and structural work, but there are no records available and reviewed by AMEC of other maintenance prior to 2008. Radiators were replaced in 2003, 2005 and 2008. Silica gel was replaced in 2008. The latest planned maintenance was in 2002, with no outstanding remarks originally. Reference "Significant Work Performed" identified by work orders in the JDE database for maintenance history. The last PM date was identified subsequently as 2010.

**Asset 5978 Transformer T4 (spare)**

Doble tests were completed in 2004. Radiators were replaced in 2007 and silica gel was replaced in 2008. Planned maintenance was performed in 2004.

**Asset 5979 Transformer T5**

Doble tests were completed in 2001 and 2009. Maintenance has been recorded as completed during years 2000 to 2005 for fan maintenance and various gauge/relay maintenance. Silica gel was replaced in 2002 and the transformer was sanded and painted in 2003. Lightning arrestors were replaced and Doble tested in 2007. The latest planned maintenance was completed in 2009.

**Asset 5980 Transformer T6**

Doble tests were completed in 2002 and 2009. Maintenance has been recorded as completed during years 2007 and 2008 for various gauge/relay maintenance. Lightning arrestor were replaced in 2007. The latest planned maintenance was completed in 2007.

**Asset 5981 Transformer T7**

Doble tests were completed in 2002. Maintenance has been recorded as completed during years 2003, 2007 and 2008 for various gauge/relay and pressure switch maintenance. Silica gel was replaced in 2002, 2006 and 2008. Structural work was completed in 2003 and 2008. The lightning counter was removed in 2004 and the lightning arrestor was replaced in 2007. The latest planned maintenance was completed 2007.

**Asset 5982 Transformer T8**

Doble tests were completed in 2001. Maintenance has been recorded as completed during years 2004 and 2008 for various gauge/relay and fan maintenance. Silica gel was replaced in 2007 and 2008. Structural work was completed in 2008. TRO Central subsequently identified that T8 also had a tap changer overhaul in 2009. The latest planned maintenance was performed in 2008.

**Asset 5982 Transformer T9**

Doble tests were completed in 2001. Maintenance has been recorded as completed during years 2000, 2004 and 2006 for various gauge/relay maintenance. A dielectric test was performed in 1983 and silica gel was replaced in 2002. The latest planned maintenance was completed in 2006.

**Asset 5983 Transformer T10**

Doble tests were completed in 2000. The transformer was sanded and painted in 2001. In 2004, the gas relay was repaired, silica gel was replaced and the lightning counter was removed. The lightning arrestor was repaired in 2007. The latest planned maintenance was completed in 2006.

**Asset 6726 Unit 1 Service Power System UST-1 Transformer**

The following maintenance has been recorded as completed: Doble tested in 2000, winding temperature gauge repaired in 2000, and silica gel replaced in 2003 and 2008. The last planned maintenance routine was performed in 2004.

**Asset 8156 Unit 2 Service Power System UST-2 Transformer**

The following maintenance has been recorded as completed: Doble tested in 2002, oil level gauge and radiators repaired in 2003, silica gel replaced in 2006, and winding temperature relay and winding temperature gauge replaced in 2007. Planned maintenance was performed in 2007.

**Asset 8716 Unit 3, Unit Service Power System UST-3 Transformer**

The following maintenance has been recorded as completed: Doble tested in 2000 and 2006, structural work in 2001, silica gel replaced in 2002 and 2008, and gas relay, oil level gauge, and radiator replaced in 2007. The control cabinet was repaired in 2008. Planned maintenance was performed in 2006.

**Asset 6727 Common Stage 1 Station Service Power SST-12 Trans**

Completed test sheets for Transformer SST12 Protection dated 2006 were available and the results were satisfactory at the time of the inspection. Relays and cases required cleaning due to ingress of dust and foreign material. The following maintenance has been recorded as completed: 69kV cable repaired, Doble test and pothead and silica gel replaced in 2002, fan motor replaced in 2003, structural work completed in 2004, and oil level gauge and radiators replaced in 2009. Planned maintenance was performed in 2009.

**Asset 5989 Common Stage 2 Station Service Power SST-34 Trans**

The following maintenance has been recorded as completed: Insulator replaced in 1999; Doble tested in 2000 and 2006, silica gel replaced in 2002 and 2007, oil temperature gauge replaced in 2004, and oil leak in conservator repaired in 2009. Planned maintenance was performed in 2006. Completed test sheets for Transformer SST34 Protection dated 2007/2008 indicate reasonable tolerances.

**Asset 271311 Transformer RT1 Unit 1 Rectifying Transformer**

Original Askarel oil was changed to Perchloroethylene (with <50mg/kg PCB's) in 2004. Completed Test Plan Activity sheets dated 2005 are available for RT1 protection, with satisfactory results at this time.

**Asset 271324 Transformer RT2 Unit 2 Rectifying Transformer**

Original Askarel oil was changed to Perchloroethylene (with <50mg/kg PCB's) in 2004. Completed Test Plan Activity sheets dated 2006 are available for RT2 protection, with satisfactory results at this time.

**Asset 271680 Transformer RT3 Unit 3 Rectifying Transformer**

Completed Test Plan Activity sheets dated 2007 for RT3 protection indicate satisfactory results at this time.

### 11.1.2.3 Condition Assessment

Overall the equipment is in reasonable good shape for its age, but an adequate sparing, testing/monitoring refurbishment and replacement program should be part of the focus, along with more rigorous and probably more frequent inspections and testing. The condition assessment of the transformers is illustrated below in Table 11-6.

**TABLE 11-6 CONDITION ASSESSMENT – TRANSFORMERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5975 | 5975 | 303236 | HRDT1 | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | 230 KV | 162 | 6,7 | Installed in 1979, the "generic age" risk of transformer failure is fairly high and rising. There has been an unusual and noticeable increase in the moisture level during the past 6 months before the test in 2009. This may be a indication that the oil needs to be reconditioned, despite oil reclaim in 2008. Moisture Remarks in the 2009 Fluid Analysis Report also deems the relative saturation as high, indicating it might be due to a recent temperature drop, moist cellulose or increased water solubility in aged oil. | 4 | (45) | 15 | 2041 | 2014 | 2014 | Yes | No | 1979 |
| 1325 | 5976 | 5976 | 61-00-69225 | HRDT2 | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | 230 KV | 163 | 6,7 | Installed in 1989, the "generic age" risk of transformer failure is low, but approaching the zone of higher risk growth. The higher oil color number could be an indication of the possible start of contaminations, and the higher power factor at 100 degrees Celsius indicates higher power loss when under operation. Moisture Remarks in the 2009 Fluid Analysis Report indicates the water content of the oil being acceptable. (Last PM date subsequently identified as 2009, same as oil test date.) | 4 | (45) | 25 | 2041 | 2013 | 2013 | Yes | No | 1989 |
| 1325 | 5977 | 5977 | 287198 | HRDT3 | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | 230 KV | 164 | 6,7 | Installed in 1978 originally on Unit 1, the "generic age" risk of transformer failure is fairly high and rising. The last electrical test were in 2002. 2009 oil tests showed higher power factors at 25 and 100 degrees Celsius which indicate higher power loss. The interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products and it is likely the cause of the high color number. Scheduled maintenance seems over-due since 2008. (Last PM date identified subsequently as 2010). | 4 | (45) | 15 | 2041 | 2016 | 2016 | Yes | No | 1978 |
| 1325 | 5978 | 5978 | 287199 | HRDT4 | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | 230 KV | 165 | 6,7 | Installed in 1970 on Unit 1 and then moved as the spare transformer in 1988, its generic age risk is fairly high. Electrical Doble tests and planned maintenance were last done in 2004. Radiators were replaced in 2007. Silica gel replaced in 2008. The condition is somewhat uncertain. | 4 | (45) | 20 | 2041 | 2011 | 2011 | Yes | No | 1970-1988 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDT5 | HRDTS | TRANSFORMERS | TRANSFORMER T5 | 230 KV | 166 | 6,7 | Installed in 1969, the unit is at a high level of risk on the basis of its time in service. No significant issues were identified in Doble tests done in 2001 and 2009. Lightning arrestors were replaced and doble tested in 2007. Planned Maintenance was done in 2009. 2009 insulating oil test results indicates higher power loss, and a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5 | 2041 | 2015 | 2015 | Yes | No | 1969 |
| 1325 | 5980 | 5980 | 287065 | HRDT6 | HRDTS | TRANSFORMERS | TRANSFORMER T6 | 230 KV | 167 | 6,7 | Installed in 1960. the unit is at a high level of risk given its time in service. No significant issues were identified in Doble tests done in 2002 and 2009. Maintenance in 2007 and 2008 for various gauges/relays and lightning arrestor replaced in 2007. 2009 insulation oil tests suggests greater thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products (possible cause of the low dielectric breakdown voltage). | 4 | (45) | 5 | 2041 | 2013 | 2013 | Yes | No | 1960 |
| 1325 | 5981 | 5981 | 287064 | HRDT7 | HRDTS | TRANSFORMERS | TRANSFORMER T7 | 230 KV | 168 | 6,7 | Installed pre-1974, the unit is at a high level of risk given its time in service. No significant issues were identified in Doble tests in 2002. Maintenance in 2003, 2007 and 2008 for various gauges/relays and pressure switches. Silica gel was replaced in 2002, 2006 and 2008. Lightning arrestor replaced in 2007. Structural work was done in 2003 and 2008. Latest Planned Maintenance was in 2007. Insulating oil tests in 2009 suggests thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products (potential cause of the low dielectric breakdown voltage). | 4 | (45) | 10 | 2041 | 2013 | 2013 | Yes | No | 1974 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDT8 | HRDTS | TRANSFORMERS | TRANSFORMER T8 | 230 KV | 169 | 6,7 | Installed in 1989, the unit is at a relatively low level of risk. No significant issues were identified in Doble tests in 2001. Maintenance in 2004 and 2008 was for various gauges/relays and fans. Silica gel was replaced in 2007 and 2008. Structural and planned maintenance work was completed in 2008. TRO Central subsequently identified that T8 also had a tap changer overhaul in 2009. Insulating oil tests in 2009 suggests thermal decomposition of cellulose, higher power loss when under operation, and a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 25 | 2041 | 2014 | 2014 | Yes | Yes | 1989 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDT9 | HRDTS | TRANSFORMERS | TRANSFORMER T9 | 13.8 kV | 170 | 6,7 | Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric test performed in 1983. The latest Planned Maintenance was in 2006. Insulating oil tests in 2009 suggests higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5 | 2041 | 2012 | 2012 | Yes | No | 1970 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDT10 | HRDTS | TRANSFORMERS | TRANSFORMER T10 | 230 KV | 171 | 6,7 | Installed in 1990, the unit is at a low level of risk due to its age. No significant issues were identified in Doble tests done in 2000. A gas relay was repaired in 2004 and silica gel was replaced in 2004. Its lightning arrestor was repaired in 2007. Latest Planned Maintenance was in 2006. The 2009 insulating oil test suggests thermal decomposition of cellulose, higher power loss when under operation, and higher solubility of polar contaminants and oxidation products (potential cause of the low dielectric breakdown voltage). | 4 | (45) | 25 | 2041 | 2012 | 2012 | Yes | Yes | 1990 |
| 1325 | 5985 | 5989 | A-3-S-7608 | HRDUST-1 | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | 69 KV | 172 | 6,7 | Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2000. Its Winding temperature gauge repaired in 2000 and silica gel replaced in 2003 and 2008. Last planned maintenance performed in 2004. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5 | 2041 | 2010 | 2010 | Yes | No | 1969 |
| 1325 | 5986 | 5986 | N/A | HRDUST-2 | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | 69 KV | 173 | 6,7 | Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2002. Maintenance: oil level gauge repaired in 2003, radiators in 2003, winding temperature relay replaced in 2007, winding temperature gauge replaced in 2007, silica gel replaced in 2006. Planned maintenance performed in 2007. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5 | 2041 | 2013 | 2013 | Yes | No | 1969 |

Table 11-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5987 | 5987 | N/A | HRDUST-3 | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | 69 KV | 174 | 6,7 | Installed in 1978, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2000 and 2006. Maintenance: structural work in 2001, silica gel in 2002 and 2008, oil level gauge in 2007, radiator replaced in 2007, gas relay in 2007, and control cabinet repaired in 2008. Planned maintenance performed in 2006. 2009 insulating oil tests suggest higher power loss, a higher solubility of polar contaminants and oxidation products and a steady trend of decrease re performance of the transformer. | 4 | (45) | 15 | 2041 | 2013 | 2013 | Yes | No | 1978 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDSST-12 | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | 69 KV | 175 | 6,7 | Installed in 1969, the unit has a relatively high level of risk due to its age. No significant issues were identified in Doble tests in 2002. Maintenance: 69kV cable repaired in 2002, pothead replaced in 2002, silica gel replaced in 2002, fan motor replaced in 2003, structural work done in 2004, oil level gauge replaced in 2009, and radiators replaced in 2009. Planned maintenance performed in 2009. 2009 insulating oil tests indicate higher power loss, and a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5 | 2041 | 2015 | 2015 | Yes | No | 1969 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDSST-34 | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | 69 kV | 176 | 6,7 | Installed in 1978, the unit has a moderately high level of risk due to its age. No significant issues were identified in Doble tests in 2000 and 2006. Maintenance: insulator replaced in 1999, silica gel replaced in 2002 and 2007, oil temperature gauge replaced in 2004, and an oil leak in conservator repaired in 2009. Planned maintenance performed in 2006. .2009 insulating oil tests indicate a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 15 | 2041 | 2012 | 2012 | Yes | No | 1978 |

Notes:
1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

. 3. Hydro TRO transmission system staff indicated that AMEC used a reference to an IEEE standard with parameters of new oil whereas NL Hydro use an IEE standard for in service transformer oil (IEEE Standard 637 Guideline which has parameters for Reclaimed Transformer Oil). NL Hydro also use SD Myers Transformer Maintenance Institute parameters for evaluating oil quality for in service transformer oil. AMEC's primary interest is that oil analyses be continued and indeed enhanced to allow trending and analyses of results as the units age.

### 11.1.2.4 Actions

Based on the condition assessment, the following actions are recommended for the transformers:

**TABLE 11-7 RECOMMENDED ACTIONS – TRANSFORMERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | | | | | HRDTS | TRANSFORMERS | TRANSFORMERS | 262 | 6,7 | Develop programs dealing with testing, overhauling, retrofitting, and modifications to extend the life of all transformers to 2041, | 2012 | 1 |
| 1325 | 5975 | 5975 | 303236 | N/A | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | 263 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2014 | 1 |
| 1325 | 5976 | 5976 | 61-00-69225 | N/A | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | 264 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2013 | 1 |
| 1325 | 5977 | 5977 | 287198 | N/A | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | 265 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2016 | 1 |
| 1325 | 5978 | 5978 | 287199 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | 266 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2011 | 1 |
| 1325 | 5979 | 5979 | A-3-S-7520 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T5 | 267 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2015 | 1 |
| 1325 | 5980 | 5980 | 287065 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T6 | 268 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2013 | 1 |
| 1325 | 5981 | 5981 | 287064 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T7 | 269 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2013 | 1 |
| 1325 | 5982 | 5982 | 61-00-68928 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T8 | 270 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2014 | 1 |
| 1325 | 5983 | 5983 | 61-00-69576 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T9 | 271 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2012 | 1 |
| 1325 | 5984 | 5984 | 61-00-69576 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T10 | 272 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2012 | 1 |
| 1325 | 5985 | 5985 | N/A | N/A | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | 273 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2010 | 1 |
| 1325 | 5986 | 5986 | N/A | N/A | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | 274 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2013 | 1 |
| 1325 | 5987 | 5987 | N/A | N/A | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | 275 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2013 | 1 |
| 1325 | 5988 | 5988 | WT-1976-1 | N/A | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | 276 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2015 | 1 |
| 1325 | 5989 | 5989 | A-3-S-7608 | N/A | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | 277 | 6,7 | Implement all requirements of Transformer Maintenance History Sheets. Comparative analyses with previous history. | 2012 | 1 |

Table 11-7 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5975 | 5975 | 303236 | N/A | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | 280 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5976 | 5976 | 61-00-69225 | N/A | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | 281 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5977 | 5977 | 287198 | N/A | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | 282 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5978 | 5978 | 287199 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | 283 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5979 | 5979 | A-3-S-7520 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T5 | 284 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5980 | 5980 | 287065 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T6 | 285 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5981 | 5981 | 287064 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T7 | 286 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5982 | 5982 | 61-00-68928 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T8 | 287 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5983 | 5983 | 61-00-69576 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T9 | 288 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5984 | 5984 | 61-00-69576 | N/A | HRDTS | TRANSFORMERS | TRANSFORMER T10 | 289 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5985 | 5985 | N/A | N/A | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | 290 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5986 | 5986 | N/A | N/A | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | 291 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5987 | 5987 | N/A | N/A | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | 292 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5988 | 5988 | WT-1976-1 | N/A | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | 293 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1325 | 5989 | 5989 | A-3-S-7608 | N/A | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | 294 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | U1 GENERATOR | GENERATOR EXCITATION SYSTEM | RT1, UNIT 1 RECTIFYING TRANSFORMER | 296 | 6,7 | Align with current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry as required . | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | U1 GENERATOR | GENERATOR EXCITATION SYSTEM | RT1, UNIT 1 RECTIFYING TRANSFORMER | 297 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271324 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | RT2, UNIT 2 RECTIFYING TRANSFORMER | 298 | 6,7 | Align with current PCB Regulation SOR/2008-273, posted in the CEPA Environmental Registry as required. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271324 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | RT2, UNIT 2 RECTIFYING TRANSFORMER | 299 | 6,7 | Dissolved gas analysis and oil quality tests and analysis, including previous years. | 2010 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271680 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | RT3, UNIT 3 RECTIFYING TRANSFORMER | 300 | 6,7 | Inspect and test the transformer: turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds and general condition and cleanliness. | 2013 | 1 |

### 11.1.2.5 Risk Assessment

The risk assessment associated with the transformer, both from a technological perspective and a safety perspective, is illustrated below in Table 11-8.

**TABLE 11-8 RISK ASSESSMENT – TRANSFORMERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5975 | 5975 | 303236 | | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | None | 264 | 7 | Electrical fault, mechanical fatigue, ops error. | 15 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 unit generation. | Test, maintain. refurbish. |
| 1325 | 5976 | 5976 | 61-00-69225 | | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | None | 265 | 7 | Electrical fault, mechanical fatigue, ops error. | 25 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 unit generation. | Test, maintain. refurbish. |
| 1325 | 5977 | 5977 | 287198 | | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | None | 266 | 7 | Electrical fault, mechanical fatigue, ops error. | 15 | N/A | 2 | C | Medium | 2 | C | Medium | Loss 1 unit generation. | Test, maintain. refurbish. |
| 1325 | 5978 | 5978 | 287199 | | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | None | 267 | 7 | Electrical fault, mechanical fatigue, ops error. | 20 | N/A | 2 | C | Medium | 2 | A | Low | Loss 1 unit generation, if failure while installed. | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5979 | 5979 | A-3-S-7520 | | HRDTS | TRANSFORMERS | TRANSFORMER T5 | None | 268 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to SB12 | Test, maintain. refurbish. |
| 1325 | 5980 | 5980 | 287065 | | HRDTS | TRANSFORMERS | TRANSFORMER T6 | None | 269 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss of supply to Line 39L to Whitbourne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5981 | 5981 | 287064 | | HRDTS | TRANSFORMERS | TRANSFORMER T7 | None | 270 | 7 | Electrical fault, mechanical fatigue, ops error. | 10 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss of supply to Line 39L to Whitbourne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5982 | 5982 | 61-00-68928 | | HRDTS | TRANSFORMERS | TRANSFORMER T8 | None | 271 | 7 | Electrical fault, mechanical fatigue, ops error. | 25 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss of supply to Line 39L to Whitbourne | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5983 | 5983 | 61-00-69576 | | HRDTS | TRANSFORMERS | TRANSFORMER T9 | None | 272 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Loss gas turbine generator generation to SB12 | Test, maintain. refurbish. |
| 1325 | 5984 | 5984 | 61-00-69576 | | HRDTS | TRANSFORMERS | TRANSFORMER T10 | None | 273 | 7 | Electrical fault, mechanical fatigue, ops error. | 25 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to SB12 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5985 | 5985 | N/A | | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | None | 274 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to UB1 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5986 | 5986 | N/A | | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | None | 275 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to UB2 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5987 | 5987 | N/A | | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | None | 276 | 7 | Electrical fault, mechanical fatigue, ops error. | 15 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to UB3 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5988 | 5988 | WT-1976-1 | | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | None | 277 | 7 | Electrical fault, mechanical fatigue, ops error. | 5 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to SB12 | Parallel paths (existing). Test, maintain. refurbish. |
| 1325 | 5989 | 5989 | A-3-S-7608 | | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | None | 278 | 7 | Electrical fault, mechanical fatigue, ops error. | 15 | N/A | 2 | C | Medium | 2 | C | Medium | Partial loss 4kV to SB34 | Parallel paths (existing). Test, maintain. refurbish. |
| 1296 | 6690 | 6691 | 6696 | 6849 | U1 GENERATOR | GENERATOR EXCITATION SYSTEM | RT1, UNIT 1 RECTIFYING TRANSFORMER | None | 279 | 7 | Electrical fault, mechanical fatigue, ops error. | (3) | N/A | 2 | C | Medium | 2 | C | Medium | Loss Unit 1 generation. | Test, maintain. refurbish. |
| 1296 | 7635 | 7636 | 7767 | 271324 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | RT2, UNIT 2 RECTIFYING TRANSFORMER | None | 280 | 7 | Electrical fault, mechanical fatigue, ops error. | (3) | N/A | 2 | C | Medium | 2 | C | Medium | Loss Unit 2 generation. | Test, maintain. refurbish. |
| 1296 | 8193 | 8194 | 8312 | 271680 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | RT3, UNIT 3 RECTIFYING TRANSFORMER | None | 281 | 7 | Electrical fault, mechanical fatigue, ops error. | 15 | N/A | 2 | C | Medium | 2 | C | Medium | Loss Unit 3 generation. | Test, maintain. refurbish. |

### 11.1.2.6 Life Cycle Curve and Remaining Life

The life cycle curves for the system are illustrated below. Several curves are required to represent the various transformers. The life curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. No equivalent hours for low load or no load operation are known or included. Operating hours for both generating mode and synchronous condensing mode (assuming Unit 1 and 2 modification in 2014) as well as physical age are important, as well as the number of significant system disturbances. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits.

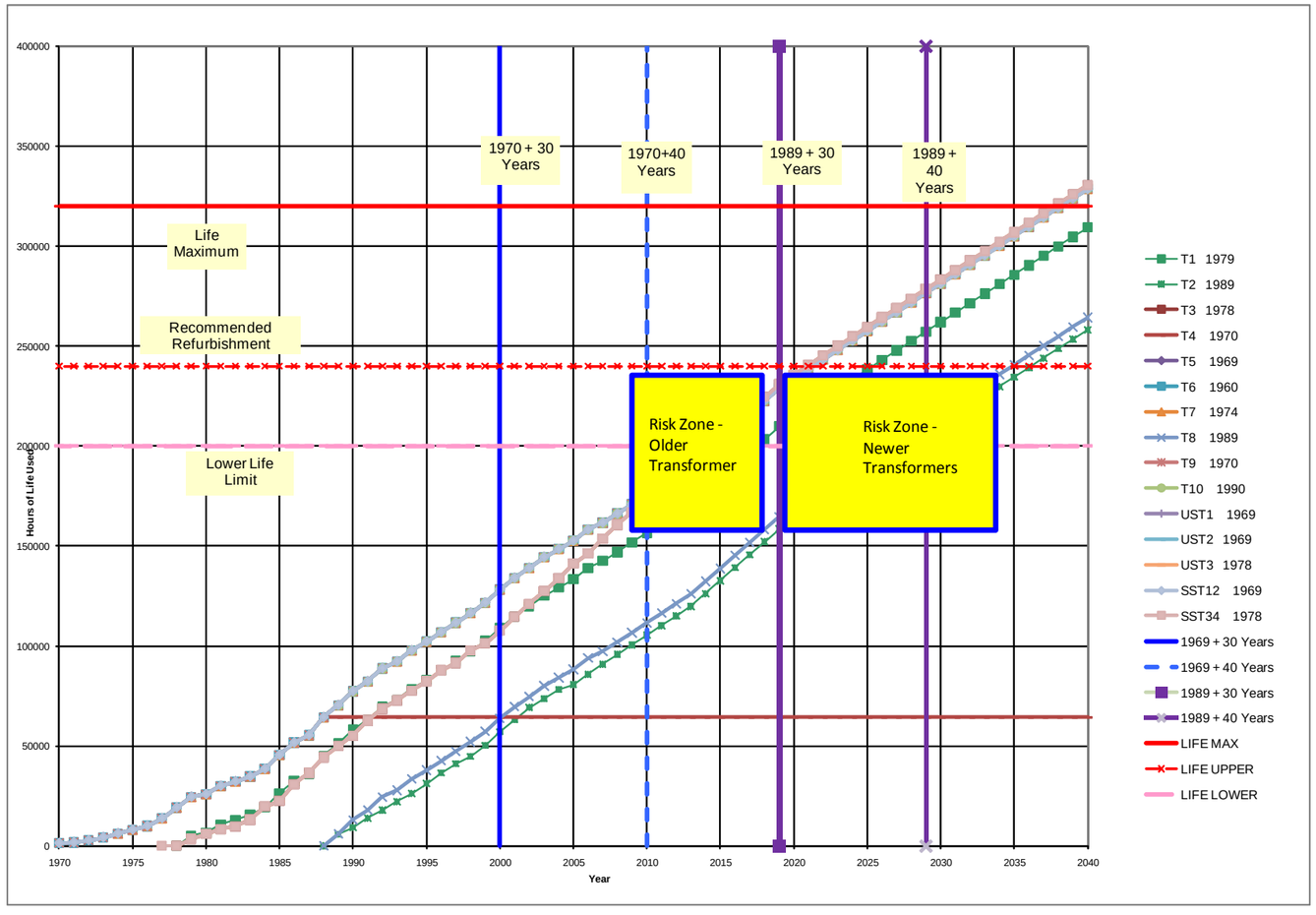



**FIGURE 11-7 LIFE CYCLE CURVE – TRANSFORMERS**

The curves indicate that the older transformers are in a critical period in their life where their reliability decreases and their likely susceptibility to system distance effects is higher. The remaining life (RL) of the transformers exceeds the end date for generation of 2020, but may not exceed the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The equipment has reached an age where reliability is a concern, particularly where system interruptions or lightning storm impacts play a role. Given the critical nature of the station and its switchyard to the supply of the mainland, a pro-active program of testing and refurbishment is a priority.

### 11.1.2.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-9 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-9 LEVEL 2 INSPECTION – TRANSFORMERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5975 | 5975 | 303236 | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | N/A | 239 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. Condition Assessment review | 2014 | 1 | $20 |
| 1325 | 5976 | 5976 | 61-00-69225 | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | N/A | 240 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. Condition Assessment review | 2013 | 1 | $17 |
| 1325 | 5977 | 5977 | 287198 | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | N/A | 241 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2016 | 1 | $6 |
| 1325 | 5978 | 5978 | 287199 | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | N/A | 242 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2011 | 3 | $6 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDTS | TRANSFORMERS | TRANSFORMER T5 | N/A | 243 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2015 | 2 | $7 |
| 1325 | 5980 | 5980 | 287065 | HRDTS | TRANSFORMERS | TRANSFORMER T6 | N/A | 244 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2013 | 2 | $6 |
| 1325 | 5981 | 5981 | 287064 | HRDTS | TRANSFORMERS | TRANSFORMER T7 | N/A | 245 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2013 | 2 | $6 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDTS | TRANSFORMERS | TRANSFORMER T8 | N/A | 246 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2014 | 2 | $7 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDTS | TRANSFORMERS | TRANSFORMER T9 | N/A | 247 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2012 | 1 | $6 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDTS | TRANSFORMERS | TRANSFORMER T10 | N/A | 248 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2012 | 2 | $6 |
| 1325 | 5985 | 5985 | N/A | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | N/A | 249 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2010 | 1 | $6 |
| 1325 | 5986 | 5986 | N/A | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | N/A | 250 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2013 | 1 | $6 |
| 1325 | 5987 | 5987 | N/A | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | N/A | 251 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2013 | 1 | $6 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | N/A | 252 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2015 | 1 | $7 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | N/A | 253 | 7 | Complete all requirements of relevant transformer maintenance history sheets and comparative analyses with previous history. | 2012 | 1 | $6 |

Table 11-9 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6016 | 6016 | 991110 | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | N/A | 254 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. Condition Assessment review | 2010 | 1 | $17 |
| 1325 | 6017 | 6017 | 991110 | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | N/A | 255 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. Condition Assessment review | 2010 | 1 | $17 |
| 1325 | 6018 | 6018 | 991110 | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | N/A | 256 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6019 | 6019 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | N/A | 257 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 3 | $6 |
| 1325 | 6020 | 6020 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T5 | N/A | 258 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 2 | $6 |
| 1325 | 6021 | 6021 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T6 | N/A | 259 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 2 | $6 |
| 1325 | 6022 | 6022 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T7 | N/A | 260 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 2 | $6 |
| 1325 | 6023 | 6023 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T8 | N/A | 261 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 2 | $6 |
| 1325 | 6024 | 6024 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T9 | N/A | 262 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6025 | 6025 | 991110 | HRDTS | TRANSFORMERS | TRANSFORMER T10 | N/A | 263 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 2 | $6 |
| 1325 | 6026 | 6026 | 991110 | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | N/A | 264 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6027 | 6027 | 991110 | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | N/A | 265 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6028 | 6028 | 991110 | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | N/A | 266 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6029 | 6029 | 991110 | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | N/A | 267 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |
| 1325 | 6030 | 6030 | 991110 | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | N/A | 268 | 7 | Perform and analyze a dissolved gas analysis and oil quality tests, and compare to previous years. | 2010 | 1 | $6 |

### 11.1.2.8 Capital Projects

The suggested typical capital enhancements for the transformers include:

**TABLE 11-10 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – TRANSFORMERS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5975 | 5975 | 303236 | HRDT1 | HRDTS | TRANSFORMERS | T1 POWER TRANSFORMER | 242 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5976 | 5976 | 61-00-69225 | HRDT2 | HRDTS | TRANSFORMERS | T2 POWER TRANSFORMER | 243 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5977 | 5977 | 287198 | HRDT3 | HRDTS | TRANSFORMERS | T3 POWER TRANSFORMER | 244 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5978 | 5978 | 287199 | HRDT4 | HRDTS | TRANSFORMERS | TRANSFORMER T4 (spare) | 245 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 3 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDT5 | HRDTS | TRANSFORMERS | TRANSFORMER T5 | 246 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5980 | 5980 | 287065 | HRDT6 | HRDTS | TRANSFORMERS | TRANSFORMER T6 | 247 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5981 | 5981 | 287064 | HRDT7 | HRDTS | TRANSFORMERS | TRANSFORMER T7 | 248 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDT8 | HRDTS | TRANSFORMERS | TRANSFORMER T8 | 249 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDT9 | HRDTS | TRANSFORMERS | TRANSFORMER T9 | 250 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDT10 | HRDTS | TRANSFORMERS | TRANSFORMER T10 | 251 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5985 | 5985 | N/A | HRDUST-1 | HRDTS | TRANSFORMERS | UST-1 TRANSFORMER | 252 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5986 | 5986 | N/A | HRDUST-2 | HRDTS | TRANSFORMERS | UST-2 TRANSFORMER | 253 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5987 | 5987 | N/A | HRDUST-3 | HRDTS | TRANSFORMERS | UST-3 TRANSFORMER | 254 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDSST-12 | HRDTS | TRANSFORMERS | STAGE 1 SST-12 TRANSFORMER | 255 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDSST-34 | HRDTS | TRANSFORMERS | STAGE 2 SST-34 TRANSFORMER | 256 | 7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |

### 11.1.3 Assets 6860 and 8730 – Common Electrical and Control Assets

The requirements for the common electrical and control systems associated with the Holyrood generators are as follows:

| | |
|---|---|
| Unit #: | Common |
| Asset Class # | BU 1297 – Assets Commons |
| SCI & System: | 7199 HRD Common Systems |
| Components: | 6904 Common, Computers Foxboro<br>7189 Common, Switchgear 4160V/600V (SB12)<br>7190 Common, Diesel Bus, DB12<br>7192 Power Centre C (SAB12, Diesel Bus DB12)<br>7197 Common, Stage 1, 129VDC Supply System<br>8771 Common, Stage 2, 129VDC Supply System<br>Units 1 to 3<br>Common Control Cables<br>Common Power Cables<br>Common 600V Metric Plugs |

#### 11.1.3.1 Description

**Asset 6904 Common Computers Foxboro**

This is integrated with the Foxboro system as a whole. Reference Foxboro Drawing D545390-SA-001 for system configuration. It was installed in 2004.

**Asset 7189 Common Switchgear 4160V/600V (SB12)**

Station Board SB12 (4160V) was manufactured by ITE and installed in 1968. The 4160V switchgear utilizes original ITE type 5HK draw-out power breakers, 1200A and 2000A. Some feeders have Schweitzer 701 motor protection relays added. All other loads utilize original P&B Golds relays. All power breakers are original. All protection, synch, and control relays are original CGE electro-mechanical.

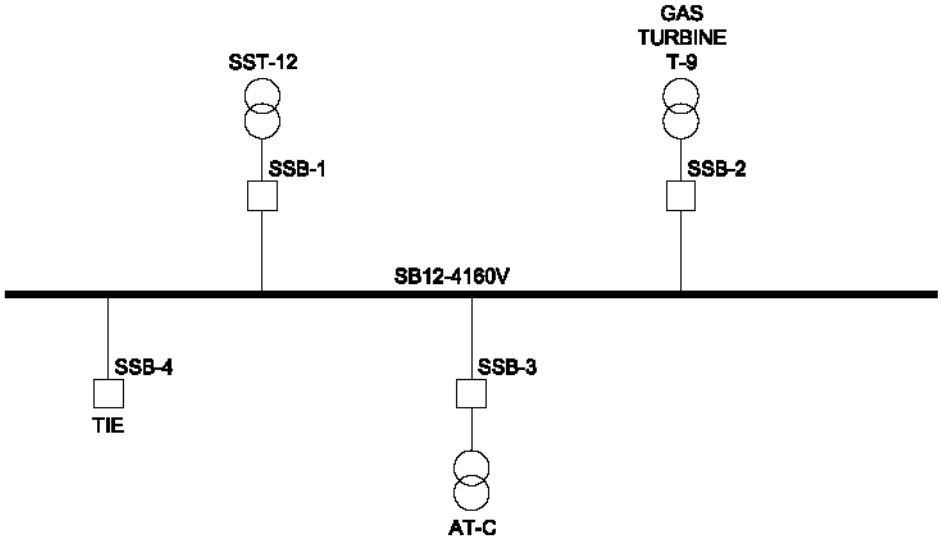



FIGURE 11-8 SB12 SWITCHGEAR

**Asset 7190 Common Diesel Bus, DB12**

Diesel Bus DB12 is part of Power Centre "C". Refer to Section 8.4.

**Asset 7192 Power Centre C (SAB12, Diesel Bus DB12)**

Power Centre "C" SAB12 and Diesel Bus DB12 (600V), was manufactured by CGE and installed in 1968. It is supplied with 600V electricity primarily from Station Board SB12 through Transformer AT-C.

The switchboard utilizes CGE AK-50 Incoming and Tie Breakers and AK-25 Feeder Breakers. Unit Aux. Transformer AT-C is a Westinghouse type ASL, AN 1500kVA, 4160V:600/347V, complete with tap-changer, +2@2.5%, Dy1, Z1=12% and was installed in 1968.

**Asset 7197 Common Stage 1 129VDC Supply System**

Unit 1 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

Unit 2 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

Common 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The panel is a type NFB, complete with FB type Breakers.

NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers.

**COMMON CABLES**

**Associated Assets**

- Asset 270296 Unit 1 Cable Raceways
- Asset 271475 Unit 2 Cable Raceways
- Asset 271763 Unit 3 Cable Raceways
- Asset 270297 Unit 1 Control Cables
- Asset 271476 Unit 2 Control Cables
- Asset 271764 Unit 3 Control Cables
- Asset 270298 Unit 1 Power Cables
- Asset 271477 Unit 2 Power Cables
- Asset 271765 Unit 3 Power Cables

Prior to 1995, preventative maintenance (PM) was carried out on power cables approximately every 10 years. Since 1995, no PM has been done and no records have been kept. Visual inspection indicated some contamination of trays in the boiler areas. Plant modifications over the past 40 years have resulted in power and control cables being placed into cable trays that have been convenient in the routings associated with the new installations.

**Common 600V Meltric Plugs**

The 600V 3 phase plugs and receptacles 30A and 60A are manufactured by Meltric and have been installed under an ongoing NLH program. This program has been completed with the exception of the LP drain pumps. There are four LP drain pump feeders remaining to modify; two servicing Unit 1 and two servicing Unit 2.

### 11.1.3.2 History - Inspection and Repair History

**Asset 6904 Common Computers Foxboro**

The DCS is a relatively new, state of the art system and regularly maintained.

**Asset 7189 Common Switchgear 4160V/600V (SB12)**

Completed Test Plan Activity sheets dated 2007 are available for Unit Board SB12 Protection. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

**Station Board SB12 - Overhauls**

- Breaker SSB-1 - overhauled 16 Sept. 2006
- Breaker SSB-2 – overhauled 1996
- Breaker SSB-3 - overhauled 17 Sept. 2006
- Breaker SSB-4 - overhauled 04 Oct. 2006

**Unit Board UB2 - Corrective Actions**

- Breaker SSB-1, Sept. 2006. (status 90)
- Breaker SSB-12, Sept. 2006. (status 90)

The Stantec Engineering Report – MCC Assessments, Section 1.0 concludes that all 4160V switchgear is applied within their ratings.

**Asset 7190 Common Diesel Bus, DB12**

Diesel Bus DB12 is a component of Power Centre "C". Maintenance request sheets, dated June 2005, indicate breaker C18 was overhauled and cleaned after being found in an extremely dusty and dirty state.

**Asset 7192 Power Centre C (SAB12, Diesel Bus DB12)**

The last PM performed was between 1992 and 1997. Breakers were sent away to an external company for maintenance and the protection relay on each breaker was changed. The Stantec Engineering Report – MCC Assessments, Section 1.0 concludes that all 600V switchgear is applied within their ratings.

**Asset 7197 Common Stage 1, 129VDC Supply System**

Common, 129VDC Distribution Panel was manufactured by Westinghouse and installed in 1973. The Panel is a type NFB, c/w FB type Breakers. NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers.

**COMMON CABLES**

**Associated Assets**

- Asset 270296 Unit 1 Cable Raceways
- Asset 271475 Unit 2 Cable Raceways
- Asset 271763 Unit 3 Cable Raceways
- Asset 270297 Unit 1 Control Cables
- Asset 271476 Unit 2 Control Cables
- Asset 271764 Unit 3 Control Cables
- Asset 270298 Unit 1 Power Cables
- Asset 271477 Unit 2 Power Cables
- Asset 271765 Unit 3 Power Cables

Prior to 1995 PM was carried out on power cables approximately on a 10 year frequency. Since 1995 no PM has been done and no records have been kept. Visual inspection indicated some contamination of trays in the boiler areas. Plant modifications over the past 40 years have resulted in power and control cables being installed in existing cable trays that have been convenient routings associated with the new installations, as well as in new trays.

### 11.1.3.3 Condition Assessment

The condition assessment of the common electrical and control assets is illustrated below in Table 11-11.

**TABLE 11-11 CONDITION ASSESSMENT – COMMON ELECTRICAL AND CONTROL ASSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 6727 | 0 | 0 | COMMON SYSTEMS | STAGE 1 STATION SERVICE POWER | STAGE 1 STATION SERVICE POWER | N/A | 5 | 6 | Not specifically addressed in detail. | 4 | (40) | 10 | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 6904 | 301712 | 0 | COMMON SYSTEMS | STATION SERVICE DCS | STATION SERVICE DCS | N/A | 6 | 6 | Not specifically addressed in detail. | 4 | (40) | 10+ | 2041 | | | No | No | 2004 |
| 1297 | 7199 | 7189 | 0 | 0 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | Switchgear 4160V/600V (SB12) | 7 | 6 | Installed in 1968. Breakers overhauled in 2006, Motor protection relays added. Tested 2007 satisfactory. Some ingress of dust and foreign material. Corrective actions on Breaker SSB-1 in 2006 (status 90) and Breaker SSB-12 in 2006. (status 90). | 3a | (40) | (5) | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7190 | 0 | 0 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | N/A | 8 | 6 | Maintenance in 2005 - Breaker C18 overhauled and cleaned after being found in an extremely dusty and dirty state. | 4 | (40) | (5) | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7191 | 0 | 0 | COMMON SYSTEMS | ESSENTIAL SERVICE MCC E1 | ESSENTIAL SERVICE MCC E1 | N/A | 9 | 6 | Not addressed. | 4 | (25) | (5) | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7192 | 0 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | N/A | 10 | 6 | Last PM between 1992 and 1997 when breakers refurbished externally, and changed the protection relay. All 600V switchgear is applied within their ratings. | 4 | (40) | (5) | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7192 | 7188 | 0 | COMMON SYSTEMS | POWER CENTER C | COMMON SERVICES MCC C1 | N/A | 11 | 6 | Acceptable condition. Old system may need replacement to align with higher firefighting flow requirements. | 4 | (25) | (5) | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7195 | 303344 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Stage 1 Batteries | N/A | 12 | 6 | New in 2006 | 3a | (25) | 20 | 2041 | | | Yes | No | 2006 |
| 1297 | 7199 | 7195 | 303345 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger A | N/A | 13 | 6 | New in 2006 | 10 | (25) | 20 | 2041 | | | Yes | No | 2006 |
| 1297 | 7199 | 7195 | 303351 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger B | N/A | 16 | 6 | Last equipment check 04 Feb 2010. 129VDC Battery Charger 2 (1969) to be replaced in 2010 | 10 | (25) | 25 | 2041 | | | Yes | Yes | 1969/2010 |
| 1297 | 7199 | 7192 | 7411 | 0 | COMMON SYSTEMS | POWER CENTER C | C.W. PUMPHOUSE MCC C6 | N/A | 17 | 6 | End of Life. Replace. | 10 | (25) | 2 | 2041 | | | No | No | 1968 |
| 1297 | 7199 | 7195 | 0 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | STAGE 1 129V D.C.SUPPLY SYSTEM | N/A | 18 | 6 | End of life. Original equipment. NFB panels and FB breakers have been superseded by PRL-3 panels and FD breakers. | 10 | (25) | (5) | 2041 | | | No | No | 1973 |
| 1297 | 7199 | 8730 | 0 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION SERVICE POWER SYSTEM | N/A | 19 | 6 | See details below. | 3a | (30) | 5 | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8731 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION SERVICE BOARD SB-34 | N/A | 20 | 6 | Acceptable condition. | 3a | (30) | 10 | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8732 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION AUXILIARY BOARD SAB-34 | N/A | 21 | 6 | Station Board SB34 Protection tests in 2007 weare satisfactory. Breakers overhauled in 2006 OK, with corrective actions on TB12 breaker, Sept, 2006. (status 90) and SAT34 breaker (status 90). | 3a | (30) | 10 | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8738 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | GENERAL PURPOSE MCC GPB-34 | N/A | 22 | 6 | Not reviewed. Aging equipment obsolescence issue. | 4 | (30) | (5) | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8740 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | TURB & BLR STANDBY MCC SDB-34 | N/A | 23 | 6 | Not reviewed. Aging equipment obsolescence issue. | 4 | (30) | (5) | 2020 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8742 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | DIESEL BUS DB-34 | N/A | 24 | 6 | Reasonable condition. Not reviewed in detail. | 3a | (30) | (10) | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8743 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | ESSENTIAL SERVICES MCC ESB-34 | N/A | 25 | 6 | Reasonable condition. Not reviewed in detail. | 3a | (30) | (5) | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8730 | 8746 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | C.W. PUMPHOUSE MCC CWP-34 | N/A | 26 | 6 | Refurbishment required. | 10 | (30) | 10 | 2041 | | | No | No | 1980 |
| 1297 | 7199 | 8771 | 0 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | N/A | 28 | 6 | Installed in 1978. Last equipment check 04 Feb. 2010. Essentially at end of life. | 10 | (25) | (5) | 2041 | | | No | No | 1978 |
| 1297 | 7199 | 8771 | 99029568 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | C & D 60 CELL BATTERY BANK | | 30 | 6 | Replaced in 1996. Last test in 2010 OK. | 4 | (25) | 10 | 2041 | 2015 | | Yes | No | 1996 |

Notes:

1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.1.3.4 Actions

Based on the condition assessment, the following actions are recommended for common electrical and control assets:

**TABLE 11-12 RECOMMENDED ACTIONS – COMMON ELECTRICAL AND CONTROL ASSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 6727 | 0 | 0 | COMMON | STAGE 1 STATION SERVICE | STAGE 1 STATION SERVICE | 8 | 6 | No recommended action. | | |
| 1297 | 7199 | 6904 | 301712 | 0 | COMMON | STATION SERVICE DCS | STATION SERVICE DCS | 9 | 6 | No recommended action. | | |
| 1297 | 7199 | 7189 | 0 | 0 | COMMON | STATION BOARD SB-12 | STATION BOARD SB-12 | 10 | 6 | Refurbish and/or replace components. | 2013 | 2 |
| 1297 | 7199 | 7190 | 0 | 0 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | 11 | 6 | Carry out inspection and testing of transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. Check bus-bar bolts sand retorqued. Overhaul in next 5 years | 2011 | 1 |
| 1297 | 7199 | 7191 | 0 | 0 | COMMON | ESSENTIAL SERVICE MCC E1 | ESSENTIAL SERVICE MCC | 12 | 6 | Not addressed in detail. Given age and service, refurbish and/or replace components | 2013 | 2 |
| 1297 | 7199 | 7192 | 0 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | 13 | 6 | Carry out inspection and testing of transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing - turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness.. Check bus-bar bolts and retorqued. | 2011 | 1 |
| 1297 | 7199 | 7192 | 7188 | 0 | COMMON | POWER CENTER C | COMMON SERVICES MCC | 14 | 6 | Refurbish or replace. | 2014 | 2 |
| 1297 | 7199 | 7192 | 7411 | 0 | COMMON | POWER CENTER C | C.W. PUMPHOUSE MCC C6 | 15 | 6 | Replace. | 2011 | 2 |
| 1297 | 7199 | 7195 | 0 | 0 | COMMON | STAGE 1 129V D.C.SUPPLY | STAGE 1 129V D.C.SUPPLY | 16 | 6 | Replace panels and breakers. | 2012 | 2 |
| 1297 | 7199 | 7195 | 303344 | 0 | COMMON | STAGE 1 129V D.C.SUPPLY | 129 VDC Stage 1 Batteries | 17 | 6 | No recommended action. | | |
| 1297 | 7199 | 7195 | 303350 | 0 | COMMON | STAGE 1 129V D.C.SUPPLY | 129 VDC Charger A | 20 | 6 | No recommended action. | | |
| 1297 | 7199 | 7195 | 303351 | 0 | COMMON | STAGE 1 129V D.C.SUPPLY | 129 VDC Charger B | 21 | 6 | Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger. | 2010 | 1 |
| 1297 | 7199 | 8730 | 0 | 0 | COMMON | STATION SERVICE POWER | STATION SERVICE POWER | 22 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8731 | 0 | COMMON | STATION SERVICE POWER | STATION SERVICE BOARD | 23 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8732 | 0 | COMMON | STATION SERVICE POWER | STATION AUXILIARY BOARD | 24 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8738 | 0 | COMMON | STATION SERVICE POWER | GENERAL PURPOSE MCC | 25 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8740 | 0 | COMMON | STATION SERVICE POWER | TURB & BLR STANDBY MCC | 26 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8742 | 0 | COMMON | STATION SERVICE POWER | DIESEL BUS DB-34 | 27 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8743 | 0 | COMMON | STATION SERVICE POWER | ESSENTIAL SERVICES MCC | 28 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8746 | 0 | COMMON | STATION SERVICE POWER | C.W. PUMPHOUSE MCC | 29 | 6 | Refurbish or replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8771 | 0 | 0 | COMMON | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | 31 | 6 | Replace as required to achieve 2020 or 2040. Not examined in detail. | 2015 | 2 |
| 1297 | 7199 | 8771 | 99029568 | 0 | COMMON | STAGE 2 129V D.C. SUPPLY | C & D 60 CELL BATTERY | 33 | 6 | Continue to monitor performance. Replace as required. | 2015 | 2 |

### 11.1.3.5 Risk Assessment

The risk assessment associated with the common electrical and control assets, both from a technological perspective and a safety perspective, is illustrated below in Table 11-13.

**TABLE 11-13 RISK ASSESSMENT – COMMON ELECTRICAL AND CONTROL ASSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 6727 | 0 | 0 | COMMON SYSTEMS | STAGE 1 STATION SERVICE POWER | STAGE 1 STATION SERVICE POWER | None | 5 | 6 | | | | | | | | | | | |
| 1297 | 7199 | 6904 | 301712 | 0 | COMMON SYSTEMS | STATION SERVICE DCS | STATION SERVICE DCS | None | 6 | 6 | Electrical failure. | 10+ | N/A | 2 | 2 | Low | 2 | B | Low | Unit trip. | Monitor and maintain. |
| 1297 | 7199 | 7189 | 0 | 0 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | Common, Switchgear 4160V/600V (SB12) | 7 | 6 | Electrical fault, mechanical fault, ops error. | (5) | N/A | 3 | B | Medium | 3 | B | Medium | Loss up to 1 unit generation. Damage to equipment. | Parallel path suply (existnig). Refurbish or replace. |
| 1297 | 7199 | 7190 | 0 | 0 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | Common, Diesel Bus, DB12 | 8 | 6 | See Power Centres ©. | (5) | N/A | 2 | C | Medium | 2 | B | Medium | Safe Unit shutdown failure. Loss of 1 unit. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 7191 | 0 | 0 | COMMON SYSTEMS | ESSENTIAL SERVICE MCC E1 | ESSENTIAL SERVICE MCC E1 | None | 9 | 6 | See detail below. | | N/A | 3 | C | Medium | 3 | B | Medium | Loss essential services causing loss 1 unit generation, damage to equipment. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 7192 | 0 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Power Centre (600V) | 10 | 6 | Electrical fault, mechanical fatigue, ops error. | (5) | N/A | 3 | B | Medium | 3 | B | Medium | Loss of part of 1 unit generation. Damage to equipment. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 7192 | 7188 | 0 | COMMON SYSTEMS | POWER CENTER C | COMMON SERVICES MCC C1 | None | 11 | 6 | Electrical fault, mechanical fatigue, ops error. | (5) | N/A | 3 | B | Medium | 3 | B | Medium | Loss common services causing loss 1 unit generation, damage to equipment. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 7192 | 7411 | 0 | COMMON SYSTEMS | POWER CENTER C | C.W. PUMPHOUSE MCC C6 | None | 12 | 6 | Electrical fault, mechanical fatigue, ops error. | 2 | N/A | 3 | B | Medium | 3 | C | High | Loss pumphouse services causing loss 1 unit generation, damage to equipment. | Refurbish or replace. |
| 1297 | 7199 | 7195 | 0 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | STAGE 1 129V D.C.SUPPLY SYSTEM | Common, Stage 1, 129VDC Supply System | 13 | 6 | Electrical fault, mechanical fault. | (3) | 0-3 Years. Replace | 3 | C | Medium | 3 | C | Medium | Fails to shut down safely. Personnel risk. | Replace |
| 1297 | 7199 | 7195 | 303344 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Stage 1 Batteries | None | 14 | | Emergency shutdown power failure | 20 | N/A | 1 | C | Low | 2 | C | Medium | Fails to shut down safely. Personnel risk. | Existing parallel path redundancy and PM program |
| 1297 | 7199 | 7195 | 303345 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger A | None | 15 | | Emergency shutdown power failure | 20 | N/A | 1 | C | Low | 2 | C | Medium | Fails to shut down safely. Personnel risk. | Existing parallel path redundancy and PM program |
| 1297 | 7199 | 7195 | 303351 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger B | None | 18 | | Emergency shutdown power failure | 25 | N/A | 1 | C | Low | 2 | C | Medium | Fails to shut down safely. Personnel risk. | Existing parallel path redundancy and PM program |
| 1297 | 7199 | 8730 | 0 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STAGE 2 STATION SERVICE POWER SYSTEM | None | 19 | 6 | Electrical fault, mechanical fault. | (10) | 0-3 Years. Replace | 3 | C | Medium | 3 | C | Medium | Fails to shut down safely. Personnel risk. | Replace |
| 1297 | 7199 | 8730 | 8731 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STATION SERVICE BOARD SB-34 | None | 20 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | B | Medium | 3 | B | Medium | Loss up to 1 unit generation. Damage to equipment. | Parallel path suply (existnig). Refurbish or replace. |
| 1297 | 7199 | 8730 | 8732 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STATION AUXILIARY BOARD SAB-34 | None | 21 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | C | Medium | 3 | B | Medium | Loss up to 1 unit generation. Damage to equipment. | Refurbish or replace. |
| 1297 | 7199 | 8730 | 8738 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | GENERAL PURPOSE MCC GPB-34 | None | 22 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | B | Medium | 3 | B | Medium | Loss common services causing loss 1 unit generation, damage to equipment. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 8730 | 8740 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | TURB & BLR STANDBY MCC SDB-34 | None | 23 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | B | Medium | 3 | B | Medium | Loss turbien & boiler area services causing loss 1 unit generation, damage to equipment. | Refurbish or replace. |
| 1297 | 7199 | 8730 | 8742 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | DIESEL BUS DB-34 | None | 24 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | C | Medium | 3 | B | Medium | Safe Unit shutdown failure. Loss of 1 unit. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 8730 | 8743 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | ESSENTIAL SERVICES MCC ESB-34 | None | 25 | 6 | Electrical fault, mechanical fatigue, ops error. | (10) | N/A | 3 | C | Medium | 3 | B | Medium | Loss essential services causing loss 1 unit generation, damage to equipment. | Parallel path suply (existing). Refurbish or replace. |
| 1297 | 7199 | 8730 | 8746 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | C.W. PUMPHOUSE MCC CWP-34 | None | 26 | 6 | Electrical fault, mechanical fatigue, ops error. | (2) | N/A | 3 | B | Medium | 3 | C | High | Loss pumphouse services causing loss 1 unit generation, damage to equipment. | Refurbish or replace. |
| 1297 | 7199 | 8771 | 0 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | None | 28 | 6 | Emergency shutdown power failure | (5) | N/A | 3 | C | Medium | 3 | C | Medium | Fails to shut down safely. Personnel risk. | Replace |
| 1297 | 7199 | 8771 | 99029568 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | C & D 60 CELL BATTERY BANK | None | 30 | 6 | Emergency shutdown power failure | 10 | N/A | 1 | C | Low | 2 | C | Medium | Fails to shut down safely. Personnel risk. | Existing parallel path redundancy and PM program |

### 11.1.3.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements. The curves are plots of current and projected operating hours (generation plus synchronous condensing mode) on the y-axis versus calendar year on the x-axis. Vertical lines represent bands of nominal years of normal base loaded life. Horizontal lines represent the ranges of equipment life based on current and historical information and expert opinion. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

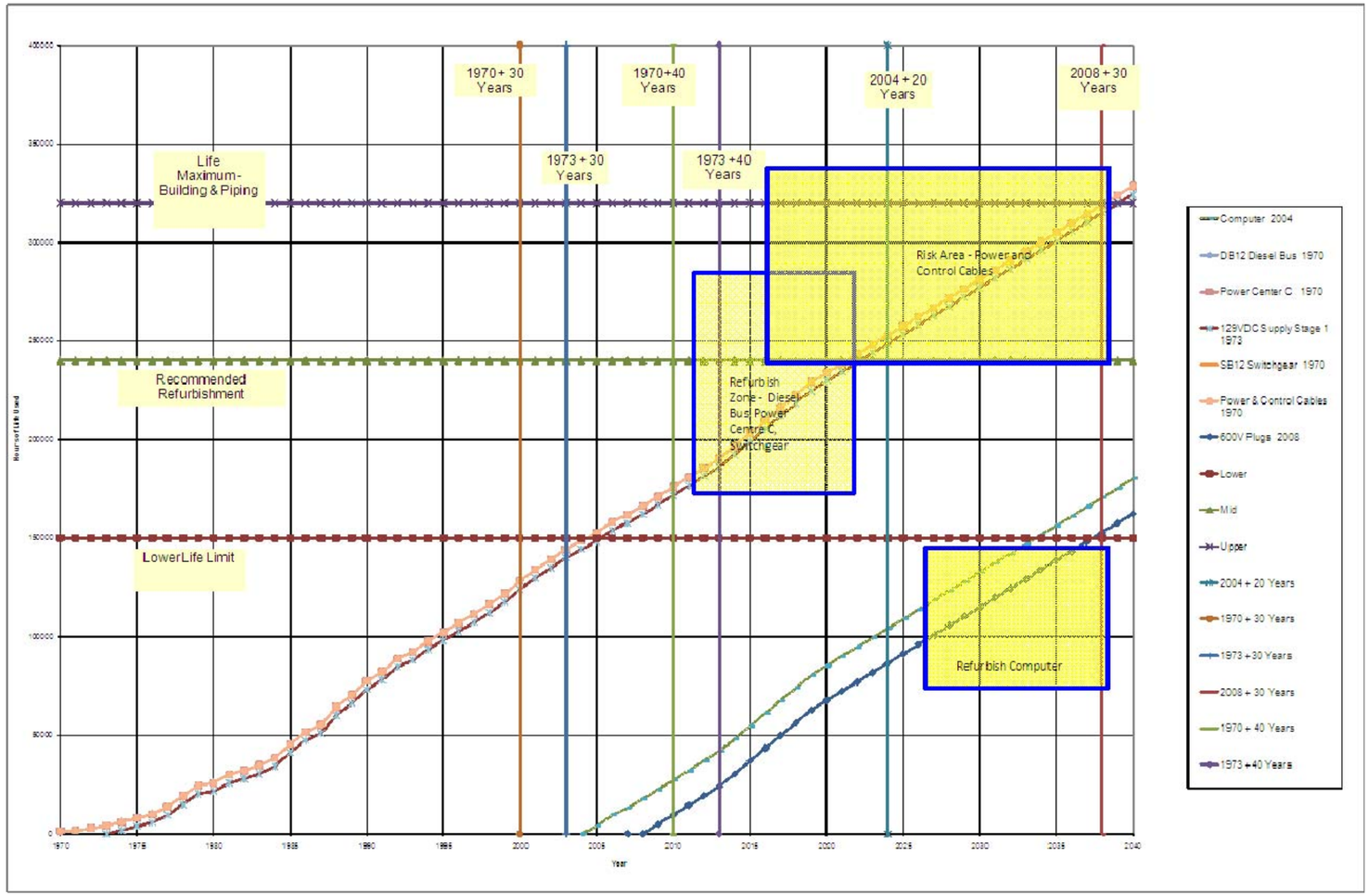



**FIGURE 11-9 LIFE CYCLE CURVE – COMMON ELECTRICAL AND CONTROL ASSETS**

The curves indicate that the remaining life (RL) of most of the common electrical and control assets exceeds the end date for generation of 2020, but not the desired life (DL) which is the end date for synchronous condensing of 2041. Further, any older switchgear such as breakers or motor control centres will need to be replaced (some possibly refurbished) within the next five years or risk increasing rates of failure.

### 11.1.3.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-14 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-14 LEVEL 2 INSPECTION – COMMON ELECTRICAL AND CONTROL ASSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 6727 | 0 | COMMON SYSTEMS | STAGE 1 STATION SERVICE POWER | STAGE 1 STATION SERVICE POWER | N/A | 5 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 6904 | 301712 | COMMON SYSTEMS | STATION SERVICE DCS | STATION SERVICE DCS | N/A | 6 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7189 | 0 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | N/A | 7 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7190 | 0 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | Power Centre C (SAB12, Diesel Bus DB12) | 8 | 6 | See Power Centre C | | | |
| 1297 | 7199 | 7191 | 0 | COMMON SYSTEMS | ESSENTIAL SERVICE MCC E1 | ESSENTIAL SERVICE MCC E1 | N/A | 9 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7192 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Power Centre C (SAB12, Diesel Bus DB12) | 10 | 6 | Inspect and test transformer AT-C and the individual AK-50 / AK-25 air circuit breakers and the bussing Check bus-bar bolts and retorqued. Transformer: turns ratio, power and dissipation factor, winding resistance, movement of coils, core grounds, taps and general condition and cleanliness. | 2011 | 2 | $75 |
| 1297 | 7199 | 7192 | 7188 | COMMON SYSTEMS | POWER CENTER C | COMMON SERVICES MCC C1 | N/A | 11 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7192 | 7411 | COMMON SYSTEMS | POWER CENTER C | C.W. PUMPHOUSE MCC C6 | N/A | 12 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7195 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | STAGE 1 129V D.C.SUPPLY SYSTEM | N/A | 13 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7195 | 303344 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC STAGE 1 BATTERIES | N/A | 14 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7195 | 303345 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC CHARGER A | N/A | 15 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7195 | 303346 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC CHARGER A | N/A | 16 | 6 | No Level 2 required. | | | |

Table 11-14 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7195 | 303350 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC CHARGER A | N/A | 17 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 7195 | 303351 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC CHARGER B | N/A | 18 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 0 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION SERVICE POWER SYSTEM | N/A | 19 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8731 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION SERVICE BOARD SB-34 | N/A | 20 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8732 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | STATION AUXILIARY BOARD SAB-34 | N/A | 21 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8738 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | GENERAL PURPOSE MCC GPB-34 | N/A | 22 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8740 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | TURB & BLR STANDBY MCC SDB-34 | N/A | 23 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8742 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | DIESEL BUS DB-34 | N/A | 24 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8743 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | ESSENTIAL SERVICES MCC ESB-34 | N/A | 25 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 8746 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | C.W. PUMPHOUSE MCC CWP-34 | N/A | 26 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8730 | 99000405 | COMMON SYSTEMS | STATION SERVICE POWER SYSTEM | INSTALL STATION SERVICE TRANSF | N/A | 27 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8771 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | N/A | 28 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8771 | 99000355 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | INSTALL D.C. DISTRIBUTION BOAR | N/A | 29 | 6 | No Level 2 required. | | | |
| 1297 | 7199 | 8771 | 99029568 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | C & D 60 CELL BATTERY BANK | N/A | 30 | 6 | No Level 2 required. | | | |

### 11.1.3.8 Capital Projects

The suggested typical capital enhancements for the common electrical and control assets include:

**TABLE 11-15 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COMMON ELECTRICAL AND CONTROL ASSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 6727 | 0 | 0 | COMMON SYSTEMS | STAGE 1 STATION SERVICE POWER | STAGE 1 STATION SERVICE POWER | 5 | 6 | No capital required. | | |
| 1297 | 7199 | 6904 | 301712 | 0 | COMMON SYSTEMS | STATION SERVICE DCS | STATION SERVICE DCS | 6 | 6 | No capital required. | | |
| 1297 | 7199 | 7189 | 0 | 0 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | 7 | 6 | Include this relaying in SB12 modernization implementation for the protection relays. | 2014 | 1 |
| 1297 | 7199 | 7189 | 0 | 0 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | 8 | 6 | Replace existing breakers SSB1, SSB2, SSB3, SSB4 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement, as required, Eaton Electrical Remote racking device (RPR2)remote racking. | 2013 | 1 |
| 1297 | 7199 | 7190 | 0 | 0 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | 9 | 6 | Diesel Bus DB12 is part of Power Centre “C” and addressed there. | 2013 | 1 |
| 1297 | 7199 | 7191 | 0 | 0 | COMMON SYSTEMS | ESSENTIAL SERVICE MCC E1 | ESSENTIAL SERVICE MCC E1 | 10 | 6 | No capital identified as required. | | |
| 1297 | 7199 | 7192 | 0 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | 11 | 6 | Change all Power Centre C (SAB12, Diesel Bus DB12) protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker C1, secondary of transformer AT-C. | 2013 | 1 |
| 1297 | 7199 | 7192 | 0 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | 12 | 6 | Overhaul to an “as new condition” of the switchgear or replace - including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to overhaul each breaker off site with essentially no interruption to plant requirements. | 2013 | 1 |
| 1297 | 7199 | 7192 | 7188 | 0 | COMMON SYSTEMS | POWER CENTER C | COMMON SERVICES MCC C1 | 13 | 6 | No capital identified as required. | | |
| 1297 | 7199 | 7192 | 7411 | 0 | COMMON SYSTEMS | POWER CENTER C | C.W. PUMPHOUSE MCC C6 | 14 | 6 | Replace. | 2011 | 1 |
| 1297 | 7199 | 7195 | 0 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | STAGE 1 129V D.C.SUPPLY SYSTEM | 15 | 6 | Replace Common Stage 1 129VDC Supply System Panel and breakers. | 2012 | 1 |
| 1297 | 7199 | 7195 | 303344 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Stage 1 Batteries | 16 | 6 | No capital required. | | |
| 1297 | 7199 | 7195 | 303345 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger A | 17 | 6 | No capital required. | | |
| 1297 | 7199 | 7195 | 303351 | 0 | COMMON SYSTEMS | STAGE 1 129V D.C.SUPPLY SYSTEM | 129 VDC Charger B | 20 | 6 | No capital required. | | |
| 1297 | 7199 | 8730 | 0 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STAGE 2 STATION SERVICE POWER SYSTEM | 21 | 6 | No capital required. | 2015 | 2 |

Table 11-15 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 8730 | 8731 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STATION SERVICE BOARD SB-34 | 22 | 6 | No capital required. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8732 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | STATION AUXILIARY BOARD SAB-34 | 23 | 6 | No capital required. | 2015 | 2 |
| 1297 | 7199 | 8730 | 8738 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | GENERAL PURPOSE MCC GPB-34 | 24 | 6 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8740 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | TURB & BLR STANDBY MCC SDB-34 | 25 | 6 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8742 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | DIESEL BUS DB-34 | 26 | 6 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8743 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | ESSENTIAL SERVICES MCC ESB-34 | 27 | 6 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8746 | 0 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | C.W. PUMPHOUSE MCC CWP-34 | 28 | 6 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8771 | 0 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | 29 | 6 | Replace | 2015 | 2 |
| 1297 | 7199 | 8771 | 99029568 | 0 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | C & D 60 CELL BATTERY BANK | 31 | | No capital required. | | |

### 11.1.4 Asset 272255 – Buildings and Building M and E System

(Detailed Technical Assessment in Working Papers - Appendices 6, 4, 17)

| | |
|---|---|
| Unit #: | COMMON |
| Asset Class # | BU 1297 – Assets Common |
| SCI & System: | 7255 HRD Buildings & Site |
| Sub-Systems: | 272255 HRD Buildings |
| Components:<br>+ | 7283 Main Powerhouse<br>7285 HRD Stage 1 Pumphouse<br>7286 HRD Stage 2 Pumphouse<br>7284 HRD Training Centre<br>7287 HRD Guardhouse<br>7288 HRD H2 and CO2 Storage Building<br>7302 HRD Shawmont building<br>7303 HRD Main Warehouse<br>7307 HRD Gas Turbine Building |

Note: Asbestos was not specifically addressed as a program is in place to address it.

#### 11.1.4.1 Description

**Asset 7283 - Main Powerhouse**

The main powerhouse building houses Unit 1, Unit 2 and Unit 3. It is a single building/structure that includes the boiler building, the steam turbine hall, and the administration block. The assessment includes:

- Structural supports
- Roof condition (Envelope)
- HVAC system

The boiler building is constructed with concrete foundations and a steel superstructure. The boilers are hung from large steel beams at the top of the building. The building was installed in two stages – Stage 1 included Units 1 and 2 and was completed in 1966, and Stage 2 – Unit 3 which was completed in 1977. The building has a flat asphalt roof. It has large motorized ventilation fans at the roof and steam coil heated air make-up rooms on the basement level.

The steam turbine hall is constructed with concrete foundations and a steel superstructure. The turbines and generators sit on large, concrete foundations and pedestals and are independent of the building. The building has a flat asphalt roof.

The administration building includes the administration block as well as the water treatment plant. It is constructed with concrete foundations, a steel superstructure, and steel panel roofing.

The powerhouse HVAC system consists primarily of a steam coil warm air make-up system. In 1992 it was installed on the basement level of the powerhouse to replace the original ventilation panels. The system also includes roof and near roof ventilation fans, and dispersed steam coil heaters that are supplemented by electric heaters. The steam supply for the auxiliary heaters is extracted from the main boilers. It was originally extracted from the plant auxiliary boiler. The original auxiliary boiler was removed.

The main powerhouse crane is a large bridge crane spanning the turbine hall. The bridge crane has both a main and auxiliary crane hook. In addition there are unit boiler house cranes. The powerhouse crane is due for a planned crane/hoist upgrade to its controls and brakes in 2012.

**Asset 7285 HRD Stage 1 Pumphouse**

The Stage 1 pump house serves Units 1 and 2 and includes an intake structure, two traveling screens and auxiliaries per unit, and two cooling water pumps and auxiliaries per unit. It was completed in 1966. The Stage 1 pumphouse also houses the raw water and fire water facilities. It is connected via an underground tunnel to the plant.

The building is an industrial class building with a concrete foundation and a steel superstructure with metal cladding. There are 15 tonne and 25 tonne overhead cranes in each pumphouse. Large concrete cavities under the floor are filled with water from the adjacent saltwater-freshwater pond.

**Asset 7286 HRD Stage 2 Pumphouse**

The Stage 2 pump house services Unit 3. It was completed in 1977 and includes an intake structure, two traveling screens and auxiliaries, and two cooling water pumps and auxiliaries. Stage 2 also has space and sub-floor provision for a fourth unit. A sump pump in one of the fourth unit CW pump pits provides turbine cooling water for Unit 3 when in synchronous condensing operation. It is connected via an underground tunnel to the plant.

The building is an industrial class building with a concrete foundation and a steel superstructure with metal cladding. There are 15 tonne and 25 tonne overhead cranes. Large concrete cavities under floor are filled with water from the adjacent saltwater-freshwater pond.

**Asset 7284 HRD Training Centre**

The training centre is a pre-engineered steel building on a concrete foundation.

**Asset 7287 HRD Guardhouse**

The guardhouse is a structural supported steel building on a concrete foundation.

**Asset 7288 HRD H2 and CO2 Storage Building**

The H2 and CO2 storage building is a pre-engineered steel building on a concrete foundation. The assessment includes the general building condition and the roof and siding condition

**Asset 7302 HRD Shawmont Building**

The Shawmont building is a pre-engineered steel building on a concrete foundation.

**Asset 7303 HRD Main Warehouse**

The main warehouse is a structural supported steel building on a concrete foundation.

**Asset 7307 HRD Gas Turbine Building**

The gas turbine building at the plant houses the gas turbine that is used in the event of a black start. The existing gas turbine building was constructed in 1986. The building is of pre-engineered, galvanized metal-panel construction, 40 ft in width and 50 ft in length with R20 exterior wall insulation. The foundation is of conventional reinforced concrete pier/wall and floor slab construction and incorporates the original turbine and module slabs. A full height concrete block partition wall was installed to completely separate the turbine/generator sections from the remaining building area. It houses a one tonne hoist/track provision to move equipment to the service area. The electrical area is divided into a battery room, a control room and an MCC/switchgear section. It has an oil drain provision for both the service and turbine rooms complete with a reinforced concrete trap. A rolling service door between the turbine and work area is provided for fire containment but easily removed for heavy equipment.

**Waste Water Treatment Plant (WWTP) Batch Reactor & Building**

The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years.

**Waste Water Treatment Plant Treatment Basin & Building**

The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed periodically. The basins are hard concrete built on bedrock.

### 11.1.4.2 History - Inspection and Repair History

**Asset 7283 Main Powerhouse**

**Structural:** No structural steel inspection reports were identified or reviewed. A visual inspection found no misaligned boiler buckstays or other members that suggested an issue. Some modifications to Unit 3 in the area of the synchronous condenser were made when it was retrofitted to ensure suitable isolation from the rest of the powerhouse similar to that of the rest of the steam turbine generator. No changes were made when Units 1 and 2 were upgraded to 175 MW from 150 MW in 1987.

**Roofs & Siding:** Prior to 2005 there was a roof life management program in place. As a result, the roofs were replaced and the siding was upgraded during the 1990 to 2000 period. This is consistent with a typical industry multi-year roofing plan after approximately 25 years in-service.

Visually the difference between the conditions of various sections of the asphalt roofing was evident. Water pooling and some reported small leaks and patching indicate the roof is approaching end of life again. The sloped metal roofs of the administration building and water treatment plant show some signs of corrosion and wear due to the marine environment.

No specific assessments of the siding condition were identified. It was upgraded in 1990-2000, and visibly appeared in reasonably good shape, although some areas are likely to need repainting or refurbishment within the next five to 10 years. Asbestos was identified as being an issue with the siding and will require considerable care. It was not addressed as it was assumed to be part of the station asbestos management program.

**HVAC:** The heating and ventilation system of the main powerhouse (boiler and steam turbine) vents on the top floor of the boiler house appear to perform well. No specific reports on their condition were identified and reviewed. Interviews identified some issues with water ingress and the ability of the fans to overcome ambient backpressure during high wind period. This has led to some units being equipped with outlet hoods (likely be adopted across the board). No other issues appear likely, provided the motors are periodically checked and maintained as required.

In 1992, the steam coil warm air make-up system was installed on the basement level of the powerhouse to replace the original ventilation panels. It was designed to automatically adjust its output to maintain the powerhouse pressure and temperature using PLC controllers. There have been issues with the system control when large building access doors have been open. As a result, the station is considering reverting to manual control of these systems.

The powerhouse auxiliary steam system is currently supplied with steam from an operating boiler supplemented by electrical heaters. The original auxiliary boiler was removed. Many of the current steam coil heaters dispersed throughout the powerhouse are in very poor condition and are operating inefficiently. While maintained regularly, primarily on an as-required basis, it is clear that the system's condition is not adequate for the requirement when the main boilers are not in-service and the units are operated as synchronous condensers.

The HVAC system for the main administration building was replaced in 2002 to 2005. With regular maintenance, it should last until 2020. Beyond 2020, additional selective replacements may be required.

**Elevators:** There are two elevators: the boiler house elevator and the administration office elevator. The boiler house elevator: is a 7 foot x 6 foot 2 inches passenger elevator capable of carrying 3500 pounds from the ground floor to tenth floor, serving eleven stops. The administration office elevator is a 6 foot 4 inches x 4 foot 5 inches passenger elevator capable of carrying 2000 pounds from the ground floor to second floor, serving two stops. Both elevators are inspected and maintained as required. There are no major failures identified in the service records, but the units' frequency of maintenance is increasing and their physical age is of concern.

**Crane:** The main powerhouse crane, the boiler building crane, and the two pumphouse cranes have been inspected regularly and where cables or brakes have been modified, they have undergone the standard 120+% waterbag test to ensure they are functioning. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes. Some improvements are planned on the controls and brake systems of the auxiliary portion of the powerhouse crane. A waterbag test would be conducted as a part of that program.

**Electrical System:** Consistent with the station PM protocol, components of the electrical systems throughout the facility are inspected and refurbished on a regular basis, but are also nearing end of life or time for a major refurbishment. Most original motor control centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

**Water Treatment Plant:** A new demineralizer section of the water treatment plant was built in 1992 as part of a building addition to the water treatment plant. The building is in good shape with only some metal roofing showing some signs of corrosion and wear from the marine environment.

**Asset 7285 HRD Stage 1 Pumphouse**

Inspection records specific to the pumphouse were not available. A visual walkthrough of the pumphouse building was performed to gauge the existing condition of the buildings.

**Structural:** The structural steel in the building appears to be in good condition with minor corrosion on some of the steel members. The concrete floor shows some signs of cracking and wear.

**Roofs & Siding:** The pumphouse roofs were included in the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. In general they are in good condition.

The siding is in reasonably good shape, with some areas likely to need repainting or refurbishment in the near future.

**Crane:** The pumphouse cranes have been inspected regularly and where cables or brakes have been modified they have undergone the standard 120+% waterbag test to ensure they are functioning properly. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes.

**Electrical System:** Components of the electrical systems are inspected and refurbished on a regular basis consistent with the station PM protocol, but are also nearing end of life or time for a major refurbishment. Most original Motor Control Centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

**Asset 7286 HRD Stage 2 Pumphouse**

Inspection records specific to the Stage 2 pumphouse were not available. A visual walkthrough of the pumphouse building was performed to gauge the existing condition of the buildings.

**Structural:** The structural steel in the building appears to be in good condition with minor corrosion on some of the steel members. The concrete floor shows some signs of cracking and wear.

**Roofs & Siding:** The pumphouse roofs were included in the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. In general, they are in good condition.

The siding is in reasonably good shape, with some areas likely to need repainting or refurbishment in the near future.

**Crane:** The pumphouse cranes have been inspected regularly and where cables or brakes have been modified they have undergone the standard 120+% waterbag test to ensure they are functioning properly. There does not appear to be any major issue with the crane, outside of the norm expected for maintenance and life management purposes.

**Electrical System:** Consistent with PM protocol, components of the electrical systems are inspected and refurbished on a regular basis but are also nearing end of life or time for a major refurbishment. Most original motor control centres require replacement in the next 1 to 5 years. Most 600V and 4kV breakers require refurbishment.

**Asset 7284 HRD Training Centre**

Inspection records specific to the training centre were not available. A visual walkthrough was performed to gauge the existing condition of the building.

**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

**Roofs & Siding:** The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

**Asset 7287 HRD Guardhouse**

Inspection records specific to guardhouse were not available. A visual walkthrough was performed to gauge the existing condition of the building.

**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

**Roofs & Siding:** The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

**Asset 7288 HRD H2 and CO2 Storage Building**

Inspection records specific to the C02 storage building were not available. A visual walkthrough was performed to gauge the existing condition of the building.

**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

**Roofs & Siding:** The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

**Asset 7302 HRD Shawmont Building**

Inspection records specific to the Shawmont building were not available. A visual walkthrough was performed to gauge the existing condition of the building.

**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

**Roofs & Siding:** The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

**Asset 7303 HRD Main Warehouse**

Inspection records specific to the main warehouse were not available. A visual walkthrough was performed to gauge the existing condition of the building.

**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted.

**Roofs & Siding:** The siding and roof are in excellent condition, aside from some modest marine ambient corrosion in some portions.

**Waste Water Treatment Plant (WWTP) Batch Reactor & Building:** The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years. The building and equipment were visually inspected and appeared to be in excellent condition, as would be expected given their age. A need for a second exit from the upper level was identified by station staff.

**Waste Water Treatment Plant Treatment Basin & Building:** The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed

periodically. The basins are hard concrete built on bedrock. The building shell, the building ventilation system, and the structural steel supports have experienced significant corrosion as a result of the humid atmosphere both inside and external to the building. The basins appear to be in good shape with minimal cracking identified in the records and a solid foundation. Some health and safety concerns were expressed with the building environment and pond exit in the event of someone falling in.

**Asset 7307 HRD Gas Turbine Building**

Inspection records specific to the turbine building were not available. A visual walkthrough of the entire gas turbine building was performed to gauge the existing condition of the building.

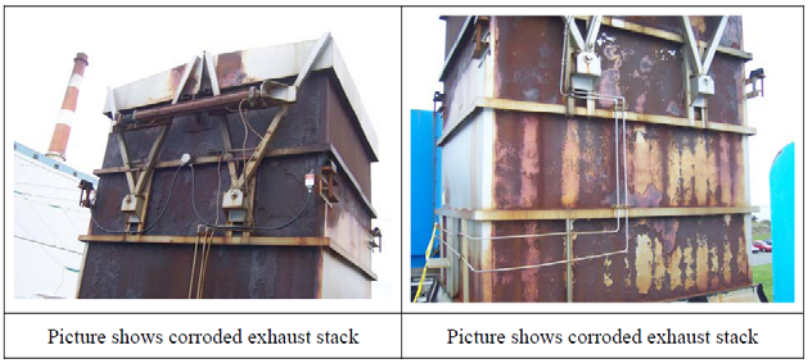
**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members located below the exhaust stack that sits on the roof of the building over the turbine.

**Roofs & Siding:** The siding and roof of the gas turbine building, specifically in the area around the stack, at the roofliner, and at the base of the building, show evidence of significant corrosion.

**Exhaust Stack:** The exhaust stack is extensively corroded with leaks into the building and into the turbine, and should be replaced.



| Picture shows corroded exhaust stack | Picture shows corroded exhaust stack |
|---|---|



| Picture shows corroded exhaust stack | Picture shows corroded exhaust stack |
|---|---|

**FIGURE 11-10 CORRODED EXHAUST STACK (GAS TURBINE PLANT)**

### 11.1.4.3 Condition Assessment

The condition assessment of the buildings and building M and E system is illustrated below in Table 11-16.

**TABLE 11-16 CONDITION ASSESSMENT – BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | | 70 | 17 | Structurally in good condition. No visual inspections of roof structures at close range possible. Little corrosion evident. Roofs replaced in 1990 to 2000, with some evidence of age and small leaks. Sloped metal roofs of Administration Building and WTP have some corrosion and wear. Some siding replaced in 1996, but lower levels not done and in need of refurbishment. | 3a | (60) | (5-30) | 2041 | 2011 | | Yes | Yes | 1969/79 |
| 1297 | 7199 | 7256 | 271815 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | N/A | 71 | 17 | Good condition. Regular inspections and load test when major modifications undertaken. Auxiliary crane brakes and controls work planned. | 4 | (50) | (2/20) | 2041 | 2011 | | No | No | 1969 |
| 1297 | 7199 | 7256 | 271816 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | BOILER ROOM HOISTS | N/A | 72 | 17 | Good condition. No information on testing | 4 | (50) | (5) | 2041 | 2011 | | No | No | 1969 |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | Plant | 73 | 17 | Service work required monthly. Acceptable condition, but decreased reliability. Nearing end of life. | 4 | (40) | 5 | 2041 | 2011 | | Yes | No | 1969 |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | Admin | 74 | 17 | Service work required monthly. Acceptable condition. Approaching end of life. | 3a | (40) | 5+ | 2041 | 2011 | | Yes | No | 1991 |
| 1297 | 7199 | 7208 | 99000093 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | N/A | 76 | | Not reviewed. Visually checked OK. Needed when synchronous condensing | 10 | (30) | 5 | 2041 | | | No | No | 1968-1970 |
| 1297 | 7199 | 7251 | 0 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEMS | N/A | 77 | | Major portion relatively new, about 5 to 6 years. No inspections. Little recent information on older underground services | 3a | (30) | (5-20) | 2041 | 2011 | | No | No | 2005-2010 |
| 1297 | 7199 | 6769 | 0 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | Auxiliary steam unit heaters | 79 | 6 | Numerous auxiliary steam unit heaters in poor condition. Auxiliary steam system upgrade needed consistent with plan for replacement energy source post synchronous condenser conversion. | 4 | (40) | 20 | 2041 | | | No | No | 1968-2004 |
| 1297 | 7199 | 6769 | 0 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | Near-roof fan weather hoods | 80 | 6 | Windy ambient conditions restricts near-roof fans ability to maintain upper powerhouse air quality levels without weather hoods. | 4 | (40) | 20 | 2041 | 2011 | | Yes | No | 1968-2010 |
| 1297 | 7199 | 7297 | 0 | 0 | COMMON SYSTEMS | WARM AIR MAKE-UP | WARM AIR MAKE-UP | N/A | 81 | 17 | Relatively new and good condition, but control improvements required to prevent nearby equipment freeze-up. | 10 | (30) | (20) | 2041 | 2011 | | Yes | No | 1969/79/99 |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | N/A | 97 | 17 | The structural systems appear generally in good condition, but no visual inspections of roof structures at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 4 | (60) | (5-20) | 2041 | | | Yes | No | 1968 |
| 1297 | 7199 | 7256 | 271817 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 1 | N/A | 98 | 17 | Good condition. Load tested within 5 years. | 3a | (50) | (10) | 2041 | 2011 | | No | No | 1969 |
| 1297 | 7199 | 7251 | 7486 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - ELECTRIC | N/A | 99 | 12,15 | Acceptable condition. Old system may need replacement to align with higher firefighting flow requirements. | 3a | (30) | 5 | 2041 | 2011 | | No | No | 1969 |
| 1297 | 7199 | 7251 | 7487 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | N/A | 100 | 12,15 | Replace diesel. | 10 | (25) | 1 | 2041 | 2011 | | No | No | 1969 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | | 101 | 17 | The structural systems appear generally in good condition, but no visual inspections of near roof structure at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 4 | (60) | (5-20) | 2041 | | | Yes | No | 1979 |
| 1297 | 7199 | 7256 | 271818 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 2 | N/A | 102 | 17 | Good condition. Load tested within 5 years. | 3a | (50) | (10) | 2041 | 2011 | | No | No | 1979 |
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | N/A | 105 | 17 | The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 3a | (40) | 20+ | 2041 | | | Yes | No | 2006 |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | N/A | 106 | 17 | The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 3a | (40) | 10 | 2041 | | | Yes | No | 1969 |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | N/A | 107 | 17 | The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 4 | (40) | (5-20) | 2041 | | | Yes | No | 1969 |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | N/A | 108 | 17 | The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 4 | (40) | (5-20) | 2041 | | | Yes | No | 1969 |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | N/A | 109 | 17 | The structural systems are in good condition with very little corrosion found and no major structural deficiencies noted. The sidings and roofs are in good shape with only some modest corrosion. | 4 | (40) | (5-20) | 2041 | | | Yes | No | 1969 |
| 1297 | 7255 | 272255 | 7304 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | N/A | 110 | 17 | Structurally in excellent condition with very little corrosion found and no major structural deficiencies noted. Some rusting siding. No second emergency egress from the building 2nd floor batch reactor work station. | 4 | (50) | (5-20) | 2041 | | | Yes | No | 1994 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | N/A | 111 | 17 | Basins building built in 1992 has some OHSA air quality concerns by staff and safety issues around basin access (exit routes). Very humid atmosphere has damaged ventilation systems and roofing. The structural steel has also experienced significant rusting. | 10 | (30) | (3) | 2041 | | | No | No | 1992 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | N/A | 112 | 17 | Structurally in good condition with modest corrosion and no significant structural deficiencies noted, except where related to gas turbine intake and exhaust. Some surface corrosion on structural members located below the exhaust stack. Sidings and roofs of the Gas Turbine Building have some corrosion requiring repair. | 4 | (40) | (2-10) | 2020 | 2010 | | Yes | No | 1986 |
| 1297 | 7255 | 272255 | 272256 | 0 | BUILDINGS AND SITE | BUILDINGS | WATER TREATMENT BUILDING | N/A | 113 | 17 | The structural systems appear generally in good condition, but no visual inspections at close range were possible. Very little corrosion was evident and no major structural deficiencies noted. The sidings and in particular the roof have some modest corrosion. | 4 | (40) | 30 | 2041 | | | Yes | Yes | 1998 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.1.4.4 Actions

Based on the condition assessment, the following actions are recommended for the buildings and building M and E system:

**TABLE 11-17 RECOMMENDED ACTIONS – BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 73 | 17 | Develop & implement roofing replacing and siding refurbishment plan. | 2012 | 1 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 74 | 17 | Modify remaining roof vents with weather hoods. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 75 | 17 | Spot check structural members near roof in crane area; and in visible corrosion areas of boiler structural support. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 76 | 17 | Optimize Warm Air Make Up system. | 2011 | 2 |
| 1297 | 7199 | 7256 | 271815 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | 77 | 17 | Implement modifications to brakes, cables of aux hoist. Continue current inspections and tests. | 2011 | 1 |
| 1297 | 7199 | 7256 | 271816 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | BOILER ROOM HOISTS | 78 | 17 | Inspection and maintain as per current program. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | 79 | 17 | Continue ongoing life maintenance. Replace powerhouse and possibly administration elevators. | 2012-2015 | 2 |
| 1297 | 7199 | 7208 | 0 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | 80 | | Maintain existing system. Develop replacement for synchronous condensing operation. Upgrade individual unit auxiliary heaters and system as required. | 2012 | 1 |
| 1297 | 7199 | 7208 | 99000093 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | 81 | | Refurbish system. Develop alternative heating system for post-generation period. | 2012 | 2 |
| 1297 | 7199 | 7251 | 0 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEMS | 82 | 15 | No recommended action. | | |
| 1297 | 7199 | 7251 | 7270 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | GAS FIRE SUPPRESSION SYSTEMS | 83 | 15 | No recommended action. | | |
| 1297 | 7199 | 7251 | 327186 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEM UPGRADE | 84 | 15 | No recommended action. | | |
| 1297 | 7199 | 6769 | 0 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | 85 | 17 | Modify ventilation hoods. Optimize control of Warm Air Make-Up System. Develop a plan for auxiliary steam heating alternative for Synchronous Condensing operation. | 2012 | 2 |
| 1297 | 7199 | 7297 | 0 | 0 | COMMON SYSTEMS | WARM AIR MAKE-UP | WARM AIR MAKE-UP | 86 | 17 | Implement management changes - manual control. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | 102 | 17 | Undertake a Level 2 inspection of the concrete floor to make a recommendation on remaining service life. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | 103 | 17 | Develop a roofing and siding refurbishment plan. Maintain program of inspection and repairs as required, including painting structural members Flag any structural deficiencies. | 2014 | 2 |

Table 11-17 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | 104 | 17 | Spot check structural members near roof in crane area. | 2011 | 1 |
| 1297 | 7199 | 7256 | 271817 | 0 | COMMON | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 1 | 105 | 17 | Inspection and maintain as per current program. | 2011 | 1 |
| 1297 | 7199 | 7251 | 7486 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - ELECTRIC | 106 | 15 | No recommended action. Evaluate increased capacity needs. | | |
| 1297 | 7199 | 7251 | 7487 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | 107 | 15 | Replace fire pump diesel. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | 108 | 17 | Undertake a Level 2 inspection of the concrete floor to make a recommendation on remaining service life. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | 109 | 17 | Develop a roofing and siding refurbishment plan. Maintain program of inspection and repairs as required, including painting structural members Flag any structural deficiencies. | 2014 | 2 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | 110 | 17 | Spot check structural members near roof in crane area. | 2011 | 1 |
| 1297 | 7199 | 7256 | 271818 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 2 | 111 | 17 | Inspection and maintain as per current program. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | 114 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | 115 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 3 |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | 116 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | 117 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | 118 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7304 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | 119 | 16 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | 120 | 16 | Perform Level 2 inspections. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | 121 | 16 | Modify building walls, ventilation, roof. | 2012 | 1 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | 122 | 17 | Repair roof, and siding corrosion, repaint. | 2011 | 1 |
| 1297 | 7255 | 272255 | 272256 | 0 | BUILDINGS AND SITE | BUILDINGS | WATER TREATMENT BUILDING | 123 | 17 | Maintain program of inspection and repairs as required, including painting structural members and siding, and roofing. Flag any structural deficiencies. | 2011 | 1 |

### 11.1.4.5 Risk Assessment

The risk assessment associated with the buildings and building M and E system, both from a technological perspective and a safety perspective, is illustrated below in Table 11-18.

**TABLE 11-18 RISK ASSESSMENT – BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life | Techno-Eco Risk Assess Model | | | Safety Risk Assess Model | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Comments | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Powerhouse Roofs | 75 | 17 | Mechanical, civil. | (5-10) | N/A | 2 | C | Medium | 2 | C | Medium | Safety – personnel, electric. | Inspect, maintain and replace. |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Powerhouse Siding | 76 | 17 | Corrosion-appearance. | (5-10) | N/A | 1 | B | Low | 1 | A | Low | Leak, appearance. | Inspect and refurbish. |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Structure - Powerhouse | 77 | 17 | Corrosion. | 30 | Visual inspection near roof reqd | 1 | B | Low | 1 | C | Low | Local failure - safety. | Inspect and refurbish. |
| 1297 | 7199 | 7256 | 271815 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | None | 78 | 17 | Crane mechanical, brake refurbishment. | (2/20) | Aux Crane Brake & Controls in 2012 | 1 | D | Medium | 1 | D | Medium | Failure during lift. Dropped load. | Isolate, refurbish, maintain, test. |
| 1297 | 7199 | 7256 | 271816 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | BOILER ROOM HOISTS | None | 79 | 17 | Mechanical failure. | (5) | N/A | 2 | C | Medium | 2 | D | Medium | Failure during lift. Dropped load. | Isolate, refurbish, maintain, test. |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | Powerhouse | 80 | | Mechanical/electrical failure. | (3) | Major refurbishment | 3 | C | Medium | 3 | D | High | Failure in service -people on board. | Maintain, inspect, refurbish. |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | Admin | 81 | | Mechanical/electrical failure. | (5) | Ongoing maintenance. Refurbish. | 2 | B | Low | 2 | D | Medium | Failure in service -people on board. | Maintain, inspect, refurbish. |
| 1297 | 7199 | 7208 | 0 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | None | 82 | | Mechanical failure/leaks. | 5 | N/A | 2 | A | Low | 2 | B | Low | Frozen equipment, possible shutdown of unit. | Inspection, maintenance, monitor, restrict. |
| 1297 | 7199 | 7251 | 0 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEMS | None | 84 | | Mechanical failure. Not addressed in detail. | (5-20) | New system for most of major plant | 2 | C | Medium | 2 | D | High | Failure to contain fire - major damage, thret to life. | Inspect, maintain, test. |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | HVAC - Powerhouse | 86 | 17 | Temp and press control; poor air quality in uper powerhouse. | 10+ | Optimization reqd | 1 | B | Low | 2 | B-C | Low-Medium | Building over/underpressure - safety. Health effects of poor air quality. | Modify control. Complete fan weather hood install. |
| 1297 | 7199 | 6769 | 0 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | None | 87 | 17 | Mechanical failure. | 20 | N/A | 1 | 3 | Low | 1 | B | Low | Unit shutdown due to low pressure. | Maintain and test. |
| 1297 | 7199 | 7297 | 0 | 0 | COMMON SYSTEMS | WARM AIR MAKE-UP | WARM AIR MAKE-UP | None | 88 | 17 | Mechanical failure. Not addressed in detail. | 20+ | Requires controls fix | 2 | A | Low | 2 | A | Low | Unit shutdown due to low pressure. | Fix controls. Maintain. |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Pumphouse 1 Roof | 104 | 17 | Leaks – end of life. | (5-10) | N/A | 1 | A | Low | 1 | B | Low | Leak – electrical issue, safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Pumphouse 1 Siding | 105 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Pumphouse 1 Structure | 106 | 17 | Corrosion-safety. | 20+ | Visual inspection near roof reqd | 1 | C | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Pumphouse 1 Concrete Floor | 107 | 17 | Corrosion-safety/perf. | (10+) | Requires Level 2 Test | 2 | C | Medium | 2 | C | Medium | Safety, unit performance, shutdown. | Inspect and refurbish. |
| 1297 | 7199 | 7256 | 271817 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 1 | None | 108 | 17 | Crane mechanical, brake failure. | (10) | N/A | 1 | C | Low | 1 | D | Medium | Isolate, refurbish, maintain, test. | Isolate, refurbish, maintain, test. |
| 1297 | 7199 | 7251 | 7486 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - ELECTRIC | None | 109 | 15 | Mechanical/electrical failure. | 5 | N/A | 3 | C | Low | 1 | C | Low | Failure during fire | Diesel back-up. Test, inspect, maintain. |
| 1297 | 7199 | 7251 | 7487 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | None | 110 | 15 | Mechanical failure. | 1 | Replacement in 2011 | 3 | C | Medium | 3 | C | High | Failure during fire | Replace with new. |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Pumphouse 2 Roof | 111 | 17 | Leaks – end of life. | (5-10) | N/A | 1 | A | Low | 1 | B | Low | Leak – electrical issue, safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Pumphouse 2 Siding | 112 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Pumphouse 2 Structure | 113 | 17 | Corrosion. | 20+ | Visual inspection near roof reqd | 1 | C | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Pumphouse 2 Concrete Floor | 114 | 17 | Temp and press control. | (10+) | Requires Level 2 Test | 2 | C | Medium | 2 | C | Medium | Safety, unit performance, shutdown. | Inspect and refurbish. |
| 1297 | 7199 | 7256 | 271818 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 2 | None | 115 | 17 | Crane mechanical, brake failure. | (10) | N/A | 1 | C | Low | 2 | D | medium | Failure during load - damage and injury. | Isolate, refurbish, maintain, test. |

Table 11-18 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | Peripheral Building Roofing | 118 | 17 | Leaks – end of life. | 20+ | N/A | 1 | A | Low | 1 | B | Low | Safety – personnel. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | Peripheral Building Siding | 119 | 17 | Corrosion-appearance. | 20+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | Structure - Peripheral Building | 120 | 17 | Corrosion. | 20+ | N/A | 1 | A | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | Peripheral Building Roofing | 121 | 17 | Leaks – end of life. | 10+ | N/A | 1 | A | Low | 1 | B | Low | Safety – personnel. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | Peripheral Building Siding | 122 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | Structure - Peripheral Building | 123 | 17 | Corrosion. | 20+ | N/A | 1 | A | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | Peripheral Building Roofing | 124 | 17 | Leaks – end of life. | 10+ | N/A | 1 | A | Low | 1 | B | Low | Safety – personnel. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | Peripheral Building Siding | 125 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | Structure - Peripheral Building | 126 | 17 | Corrosion. | 20+ | N/A | 1 | A | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | Peripheral Building Roofing | 127 | 17 | Leaks – end of life. | 10+ | N/A | 1 | A | Low | 1 | B | Low | Safety – personnel. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | Peripheral Building Siding | 128 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | Structure - Peripheral Building | 129 | 17 | Corrosion. | 20+ | N/A | 1 | A | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | Peripheral Building Roofing | 130 | 17 | Leaks – end of life. | 10+ | N/A | 1 | A | Low | 1 | B | Low | Safety – personnel. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | Peripheral Building Siding | 131 | 17 | Corrosion-appearance. | 5+ | N/A | 1 | A | Low | 1 | A | Low | Leak, appearance. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | Structure - Peripheral Building | 132 | 17 | Corrosion. | 20+ | N/A | 1 | A | Low | 1 | C | Low | Local failure - safety. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7304 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | Batch reactor Building | 133 | 16 | Corrosion-roof, walls. | 20+ | Visual inspection near roof reqd | 1 | A | Low | 1 | B | Low | Roof leak – minor impact. | Inspect and maintain. |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Treatment Basin Building | 134 | 16 | Corrosion-roof, walls. | (3) | Likely <5 yrs. Inspections not required to assess the remaining life. | 3 | A | Low | 3 | C | High | Safety issue. | Refurbish or replace. |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | GTG Building | 135 | 13,17 | Roof leaks. | (2-10) | N/A | 3 | C | Medium | 3 | B | Medium | Loss of generator, equipment damage. | Inspect and refurbish. |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | GTG Building | 136 | 13,17 | Side corrosion and appearance. | 5 | N/A | 1 | A | Low | 1 | A | Low | Appearance/equipment damage. | Inspect and refurbish. |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | Gas Turbine Building Roofing | 137 | 13,17 | Leaks – end of life. | (1) | N/A | 2 | B | Low | 2 | B | Medium | Safety – personnel. | Inspect and refurbish. |

### 11.1.4.6 Life Cycle Curve and Remaining Life

The life cycle curves for the buildings are illustrated below – Powerhouse, Stage 1 Pumphouse, Stage 2 Pumphouse and the peripheral buildings. Several curves are required to represent the various buildings and their operational timing. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various buildings. It also has several horizontal lines that represent a range of practical equipment life limits in years. The risk area boxes provide an indication of the timing of potential issues either from an age and calendar perspective.

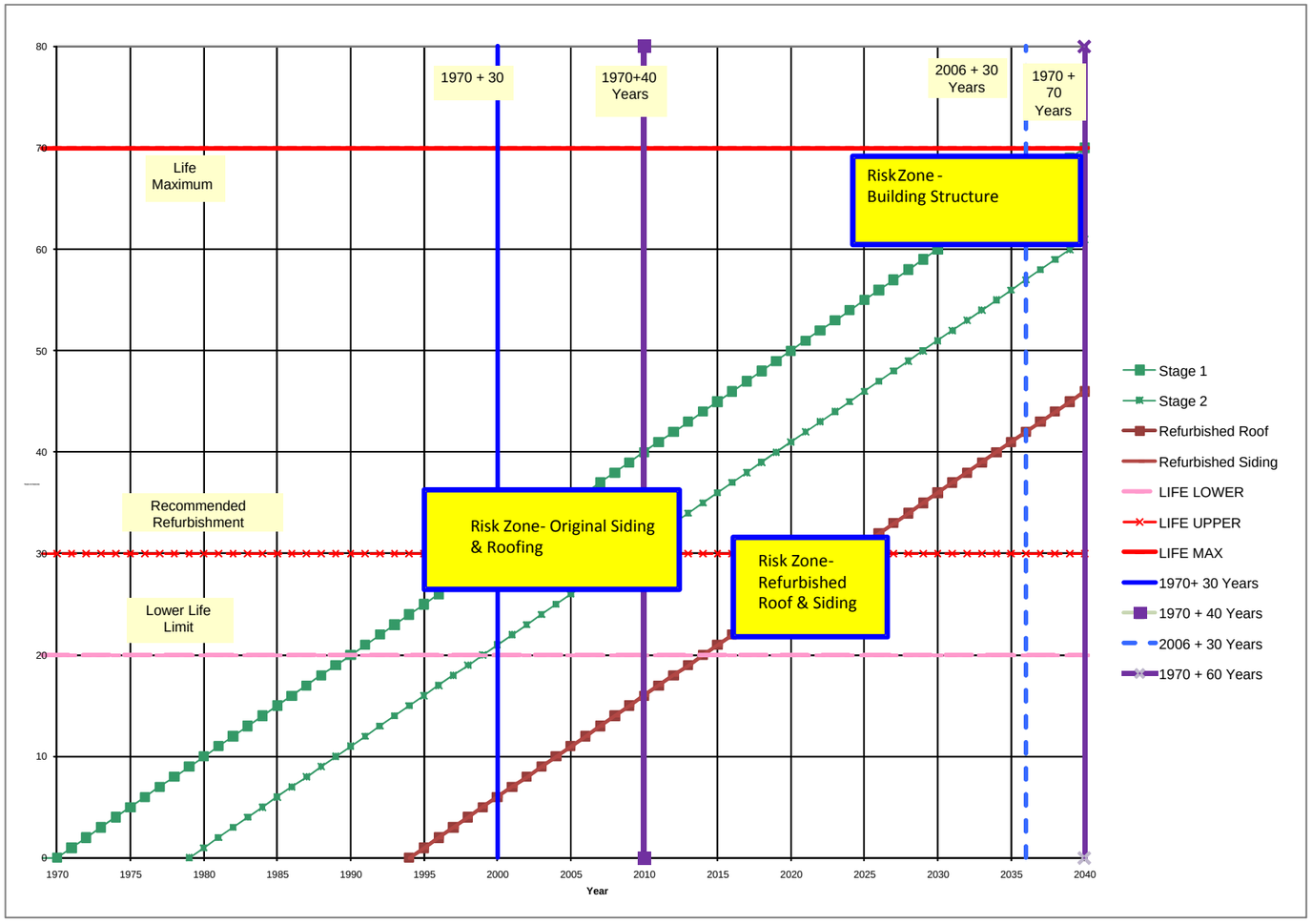



**FIGURE 11-11 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (POWERHOUSE)**

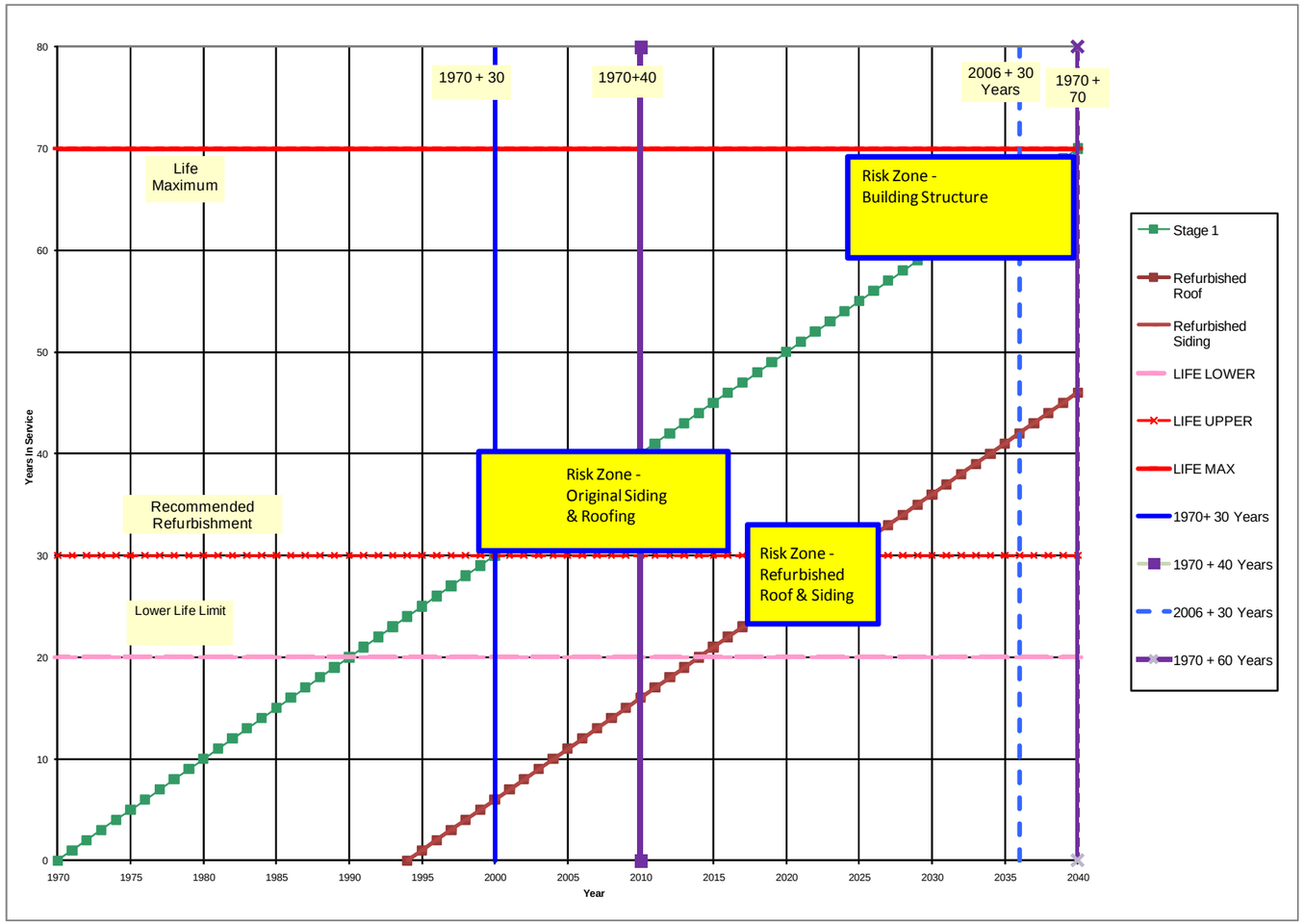



**FIGURE 11-12 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (STAGE 1 PUMPHOUSE)**

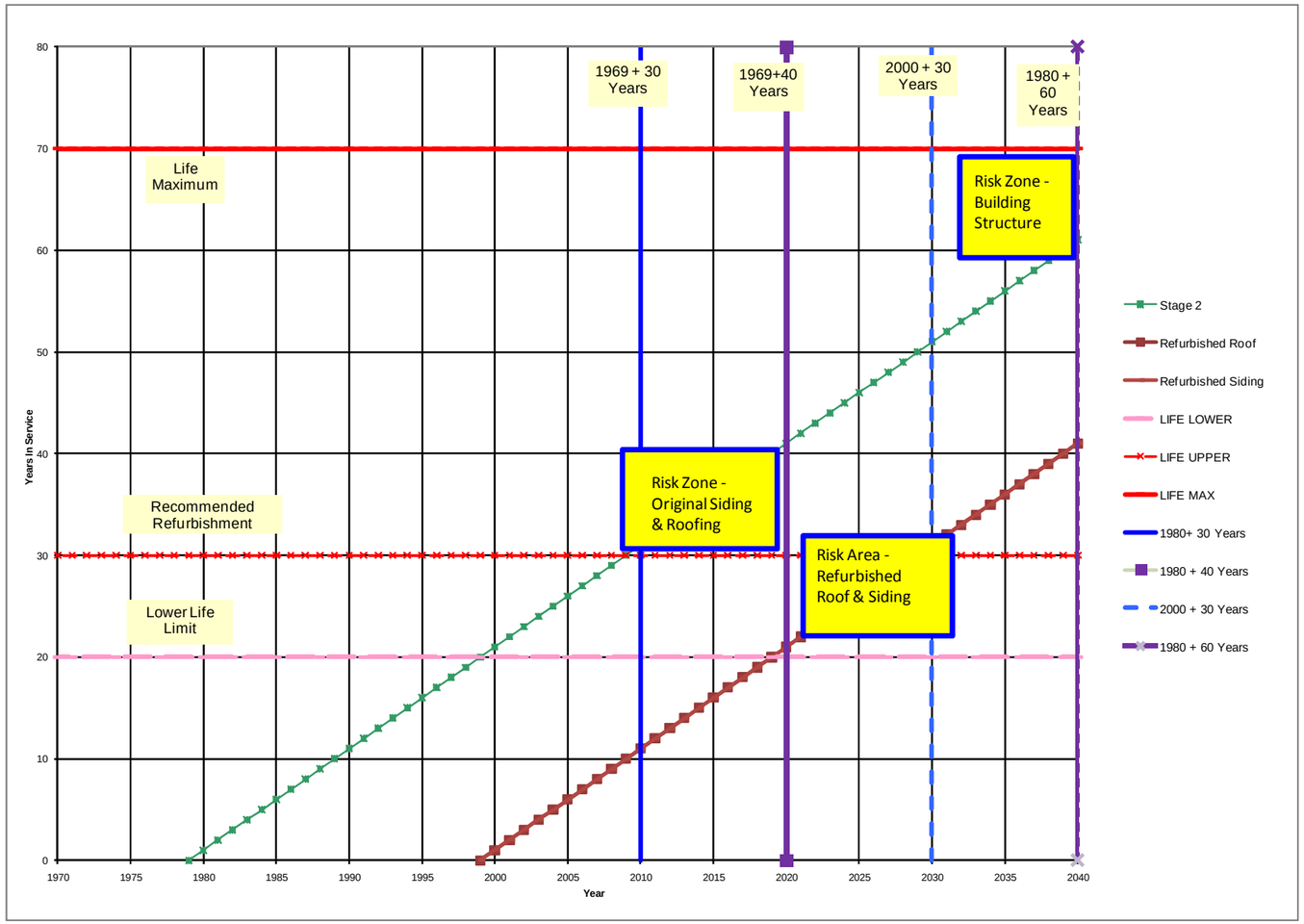



**FIGURE 11-13 LIFE CYCLE CURVE - BUILDINGS AND BUILDING M AND E SYSTEM (STAGE 2 PUMPHOUSE)**

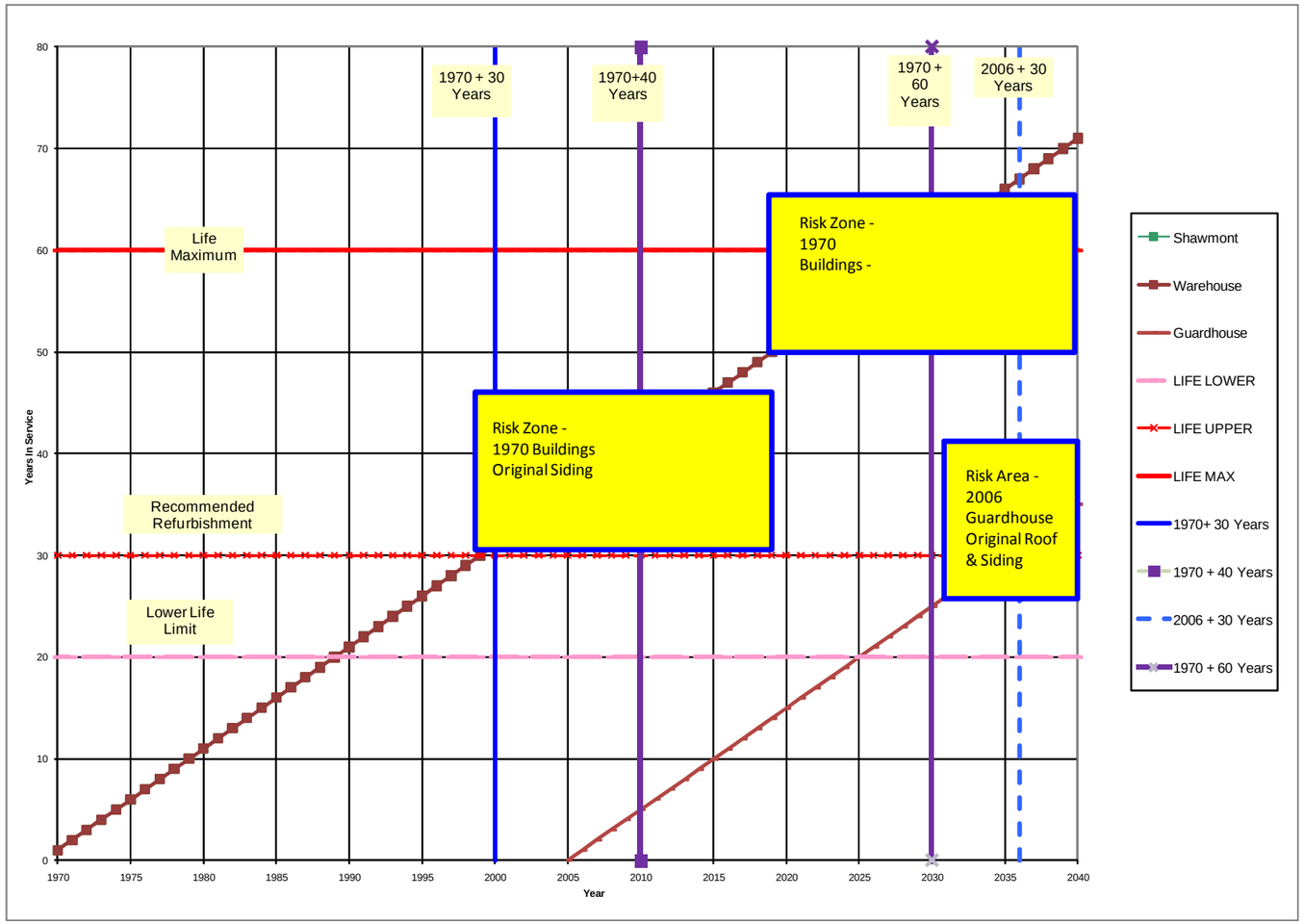



**FIGURE 11-14 LIFE CYCLE CURVE – BUILDINGS AND BUILDING M AND E SYSTEM (PERIPHERAL BUILDINGS)**

The curves indicate that the remaining life (RL) of most buildings exceeds the generation end date of 2020 and likely the desired life (DL) which is the end date for synchronous generation of 2041. The implementation of a roofing and siding refurbishment program will be necessary between the 2015 to 2025 period, and later for newer buildings or parts of buildings (WTP, guardhouse). The basic structure of most buildings is considered sound, but with limited data available. The primary M and E system of concern (not shown) are the powerhouse house elevators which are likely nearing the end of their reliable service life and should have a major refurbishment or be replaced. Cranes are an issue to continue regular testing, but no specific life issues were identified. Other aspects such as HVAC also will come into play (i.e. condenser vacuum venting, upper roof vent wind protection) in the short term, but nothing major beyond these in the immediate future.

### 11.1.4.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-19 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-19 LEVEL 2 INSPECTION – BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7283 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Powerhouse | 83 | 17 | Level 2 test check of structural steel checks especially in crane and turbine hall area. | 2014 | 3 | $5 |
| 1297 | 7255 | 272255 | 7283 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | N/A | 84 | 17 | No Level 2 required. | | | |
| 1297 | 7199 | 7256 | 271815 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | N/A | 85 | 17 | No Level 2 required. | | | |
| 1297 | 7199 | 7256 | 271816 | COMMON SYSTEMS | CRANES AND HOISTS | BOILER ROOM HOISTS | N/A | 86 | 17 | No Level 2 required. | | | |
| 1297 | 7199 | 7208 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | N/A | 87 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7208 | 99000093 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | N/A | 88 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7251 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEMS | Fire Supply Lines | 89 | 15 | No Level 2 - Consider NDE of major fire supply lines (single contingency failure) – in-pipe crawler of other device to check for thickness and/or leaks. | | | |
| 1297 | 7199 | 7251 | 7270 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | GAS FIRE SUPPRESSION SYSTEMS | N/A | 90 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 6769 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | N/A | 91 | NA | No Level 2 required. | | | |
| 1297 | 7199 | 7297 | 0 | COMMON SYSTEMS | WARM AIR MAKE-UP | WARM AIR MAKE-UP | N/A | 92 | 17 | No Level 2 required. | | | |
| 1297 | 7255 | 272255 | 7285 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Pumphouse | 95 | 17 | Inspect and test concrete floor slabs in areas exhibiting distress to determine the condition of the concrete and steel reinforcement - the east-west walkways along the north end of Pumphouse 1&2 at El. 11.17' - four cores. Suitable cores (assume a total of six cores) tested for compressive strength; and chloride ion profile. If needed, a corrosion potential survey will assist in evaluating the extent and severity of the corrosion. | 2011 | 2 | $15 |

Table 11-19 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7285 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Stoplogs | 96 | 17 | Inspect stoplog seals area -See Units. | 2011 | 2 | (Incl in 95) |
| 1297 | 7199 | 7256 | 271817 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 1 | N/A | 97 | 17 | No Level 2 required. | | | |
| 1297 | 7199 | 7251 | 7486 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - ELECTRIC | N/A | 98 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7251 | 7487 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | N/A | 99 | N/A | No Level 2 required. | | | |
| 1297 | 7255 | 272255 | 7286 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Pumphouse | 100 | 17 | Inspect and test concrete floor slabs in areas exhibiting distress to determine the condition of the concrete and steel reinforcement - included the east-west walkways along the north end of Pumphouse 3 at El. 11.17' - four cores. Suitable cores (assume a total of six cores) tested for compressive strength; and chloride ion profile. If needed, a corrosion potential survey will assist in evaluating the extent and severity of the corrosion. | 2011 | 2 | $15 |
| 1297 | 7255 | 272255 | 7286 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Stoplogs | 101 | 17 | Inspect stoplog seals area - See Units. | 2011 | 2 | (Incl in 100) |
| 1297 | 7199 | 7256 | 271818 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 2 | N/A | 102 | 17 | No Level 2 required. | | | |
| 1297 | 7255 | 272255 | 7287 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | Peripheral | 105 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | | | |
| 1297 | 7255 | 272255 | 7284 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | Peripheral | 106 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | | | |
| 1297 | 7255 | 272255 | 7288 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | Peripheral | 107 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | | | |
| 1297 | 7255 | 272255 | 7302 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | Peripheral | 108 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | | | |
| 1297 | 7255 | 272255 | 7303 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | Peripheral | 109 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | | | |
| 1297 | 7255 | 272255 | 7304 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | Equalization Treatment Building | 110 | 16 | Inspection of structural steel members - thickness measurements of the steel members to determine how much cross section loss. | 2011 | 3 | (Incl in 111) |
| 1297 | 7255 | 272255 | 7305 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Equalization Basin Tanks | 111 | 16 | Inspection of the two equalization treatment basin tanks - cores will be taken from the concrete walkways and tested for compressive strength and chloride ion profile. | 2011 | 3 | $37 |
| 1297 | 7255 | 272255 | 7307 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | GTG | 112 | 17 | No Level 2 required – see GT system analyses. | | | |
| 1297 | 7255 | 272255 | 272256 | BUILDINGS AND SITE | BUILDINGS | WATER TREATMENT BUILDING | Peripheral | 113 | 17 | No Level 2 required. Roof structural steel visual checks could lead to more detailed investigation. | 2011 | 3 | $0 |

### 11.1.4.8 Capital Projects

The suggested typical capital enhancements for the buildings and building M and E system include:

**TABLE 11-20 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 70 | 17 | Re-paint any corroded steel members in boiler house building to help stop corrosion. Also, repair any leaky pipes to ensure that steel is not exposed to water. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 71 | 17 | Prepare and implement roofing replacement and siding upgrade plan in 2012-13 for 2015-2020. | 2015 | 1 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 72 | 17 | Modify roof vents hoods. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7283 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | 73 | 17 | Optimize warm air make up system. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7283 | 7306 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | 74 | | Refurbish/replace powerhouse and administration elevators. | 2012-2015 | 2 |
| 1297 | 7199 | 7256 | 271815 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | 75 | | Replace controls and brakes for auxiliary (and main if necessary) crane. | 2011 | 1 |
| 1297 | 7199 | 7256 | 0 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | CRANES AND HOISTS | 76 | | No capital required. | | |
| 1297 | 7199 | 7256 | 271816 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | BOILER ROOM HOISTS | 77 | | No capital required. | | |
| 1297 | 7199 | 7208 | 0 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | 78 | | No capital required. | | |
| 1297 | 7199 | 7208 | 99000093 | 0 | COMMON SYSTEMS | AUXILIARY STEAM SYSTEM | AUXILIARY STEAM SYSTEM | 79 | | No capital required. | | |
| 1297 | 7199 | 7251 | 0 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PROTECTION SYSTEMS | 80 | | No capital required. | | |
| 1297 | 7199 | 7251 | 7270 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | GAS FIRE SUPPRESSION SYSTEMS | 81 | | No capital required. | | |
| 1297 | 7199 | 6769 | 0 | 0 | COMMON SYSTEMS | HEATING AND VENTILATION | HEATING AND VENTILATION | 82 | | No capital required. | | |
| 1297 | 7199 | 7297 | 0 | 0 | COMMON SYSTEMS | WARM AIR MAKE-UP | WARM AIR MAKE-UP | 83 | | No capital required. | | |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | 99 | | Re-paint any corroded steel members to prevent further corrosion lost to members. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7285 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | 100 | | Repaint and/or refurbish roofing and siding as required. | 2012 | 2 |
| 1297 | 7199 | 7256 | 271817 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 1 | 101 | | No capital required. | | |
| 1297 | 7199 | 7251 | 7486 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - ELECTRIC | 102 | | No Capital, unless larger pump is required to supply enhanced fire protection system. | | |
| 1297 | 7199 | 7251 | 7487 | 0 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | 103 | | Replace fire pump diesel. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | 104 | | Re-paint any corroded steel members to prevent further corrosion lost to members. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7286 | 0 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | 105 | | Repaint and/or refurbish roofing and siding as required. | 2012 | 2 |
| 1297 | 7199 | 7256 | 271818 | 0 | COMMON SYSTEMS | CRANES AND HOISTS | PUMPHOUSE CRANE STAGE 2 | 106 | | No capital required. | | |

Table 11-20 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7287 | 0 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | 109 | | Refurbish and re- paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2015 | 3 |
| 1297 | 7255 | 272255 | 7284 | 0 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | 110 | | Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2013 | 3 |
| 1297 | 7255 | 272255 | 7288 | 0 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | 111 | | Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2013 | 3 |
| 1297 | 7255 | 272255 | 7302 | 0 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | 112 | | Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2012 | 3 |
| 1297 | 7255 | 272255 | 7303 | 0 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | 113 | | Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2013 | 3 |
| 1297 | 7255 | 272255 | 7304 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | 114 | | Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | 115 | 16 | Replace/modify WWTP Treatment Basin building. Refurbish and re-paint siding and steel members and roofing as required. Fix any structural deficiencies as they appear . | 2012 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | 116 | 16 | Improve WWTP basins oil capture and basin escape accesses. | 2012 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | 117 | 16 | Replace/modify WWTP Treatment Basin building. | 2012 | 1 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | 118 | 17 | Re-paint any corroded steel members. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | 119 | 17 | Replace stack and affected roof areas. | 2011 | 1 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | 120 | 17 | Refurbish and re- paint siding and roofing as required. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7307 | 0 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | 121 | 17 | Replace air intake for marine environment - filter media and/or intake structure. | 2011 | 1 |
| 1297 | 7255 | 272255 | 272256 | 0 | BUILDINGS AND SITE | BUILDINGS | WATER TREATMENT BUILDING | 122 | | No capital required. | | |

### 11.1.5 Asset 7206 – Hydrogen, Nitrogen, and Carbon Dioxide Supply Systems

The requirements for the hydrogen, nitrogen, and carbon dioxide supply systems are as follows:

| | |
|---|---|
| Unit #: | Common |
| Asset Class # | BU 1297 – Assets Commons |
| SCI & System: | 7199 HRD Common Systems |
| Sub-Systems: | 7205 Compressed Air Systems |
| Components: | 7236 Hydrogen Storage & Supply<br>7237 Carbon Dioxide Storage & Supply<br>7238 Nitrogen Storage & Supply |

#### 11.1.5.1 Description

| | |
|---|---|
| Manufactured/Delivered | 1969 |
| In-Service Date | Sep 1970 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing Start Date | Jan 2015 |
| Synchronous Condensing End Date | Dec 2041 |

The scope examined includes only the hydrogen, nitrogen, and carbon dioxide storage and delivery elements. The building itself is addressed separately.

Hydrogen, nitrogen, and carbon dioxide are supplied from a gas storage steel building to the east of the powerhouse. Both gases, as well as nitrogen, are stored in high pressure cylinder packs connected to lines that go underground to the plant to the individual units. A cost and reliability issue with the hydrogen system is that there is no other major Newfoundland user. There is a Newfoundland based supplier and hydrogen has to be shipped from off-island.



FIGURE 11-15 HYDROGEN STORAGE RACKS



FIGURE 11-16 HYDROGEN STORAGE BUILDING




FIGURE 11-17 HYDROGEN LINES IN POWERHOUSE



FIGURE 11-18 HYDROGEN LINES INTO POWERHOUSE

#### 11.1.5.2 History - Inspection and Repair History

Inspections of the system are performed annually as well as frequent systems checks by operators and ongoing system monitoring. No specific testing information was identified. Interviews identified no unusual conditions or concerns, except the difficulties and costs associated with the supply of hydrogen using the current procurement approach. Some representative sampling of the distribution system piping for thickness testing is likely warranted if the entire system is not replaced as part of the new on-site hydrogen production project.

### 11.1.5.3 Condition Assessment

The condition assessment of the hydrogen, nitrogen, and carbon dioxide supply systems is illustrated below in Table 11-21.

**TABLE 11-21 CONDITION ASSESSMENT – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7206 | 0 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | N/A | 59 | 17 | Not reviewed in detail. Visually checked OK. | 4 | (30) | 20 | 2041 | 2011 | | Yes | No | 1968-1970 |
| 1297 | 7199 | 7206 | 7236 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | N/A | 60 | 17 | Not reviewed in detail. Visually checked OK. | 4 | (30) | 20 | 2041 | 2011 | | Yes | No | 1968-1970 |
| 1297 | 7199 | 7206 | 7237 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | CARBON DIOXIDE STORAGE/SUPPLY | N/A | 61 | 17 | Not reviewed in detail. Visually checked OK. | 4 | (30) | 20 | 2041 | 2011 | | Yes | No | 1968-1970 |
| 1297 | 7199 | 7206 | 7238 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | NITROGEN STORAGE/SUPPLY SYSTEM | N/A | 62 | 17 | Not reviewed in detail. Visually checked OK. | 4 | (30) | 20 | 2041 | 2011 | | Yes | No | 1968-1970 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.1.5.4 Actions

Based on the condition assessment, the following actions are recommended for the hydrogen, nitrogen, and carbon dioxide supply systems:

**TABLE 11-22 RECOMMENDED ACTIONS – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7206 | 0 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | 63 | 17 | No recommended action. | | |
| 1297 | 7199 | 7206 | 7236 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | 64 | 17 | Maintain current inspection and maintenance until system replaced by low pressure bulk storage. Distribution pipe representative sampling and thickness checks. | 2012 | 1 |
| 1297 | 7199 | 7206 | 7237 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | CARBON DIOXIDE STORAGE/SUPPLY | 65 | 17 | Maintain current inspection and maintenance. Distribution pipe representative sampling and thickness checks. | 2011 | 1 |
| 1297 | 7199 | 7206 | 7238 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | NITROGEN STORAGE/SUPPLY SYSTEM | 66 | 17 | Maintain current inspection and maintenance. Distribution pipe representative sampling and thickness checks. | 2011 | 1 |

### 11.1.5.5 Risk Assessment

The risk assessment associated with the hydrogen, nitrogen, and carbon dioxide supply systems, both from a technological perspective and a safety perspective, is illustrated below in Table 11-23.

**TABLE 11-23 RISK ASSESSMENT – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life | Techno-Eco Risk Assess Model | | | Safety Risk Assess Model | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Comments | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 7199 | 7206 | 0 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | None | 64 | 17 | Mechanical failure/leaks/fire. | 20 | N/A | 2 | B | Low | 2 | B | Low | leaks, Fire | Inspection, maintenance, monitor, restrict. |
| 1297 | 7199 | 7206 | 7236 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | None | 65 | 17 | Mechanical failure/leaks/fire. | 20 | Plan for on-site production to replace | 2 | C | Medium | 3 | C | Medium | Units shutdown.. Fire. | Inspection, maintenance, monitor, restrict. Representative tube sampling. |
| 1297 | 7199 | 7206 | 7237 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | CARBON DIOXIDE STORAGE/SUPPLY | None | 66 | 17 | Mechanical failure/leaks. | 20 | N/A | 2 | C | Medium | 3 | C | Medium | Personnel safety risk. Units shutdown. | Inspection, maintenance, monitor, restrict. Representative tube sampling. |
| 1297 | 7199 | 7206 | 7238 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | NITROGEN STORAGE/SUPPLY SYSTEM | None | 67 | 17 | Mechanical failure/leaks. | 20 | N/A | 2 | C | Medium | 3 | B | Medium | Safety risk. Units shutdown. | Inspection, maintenance, monitor, restrict. Representative tube sampling. |

### 11.1.5.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are included to represent the system and the piping (and building structure). The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

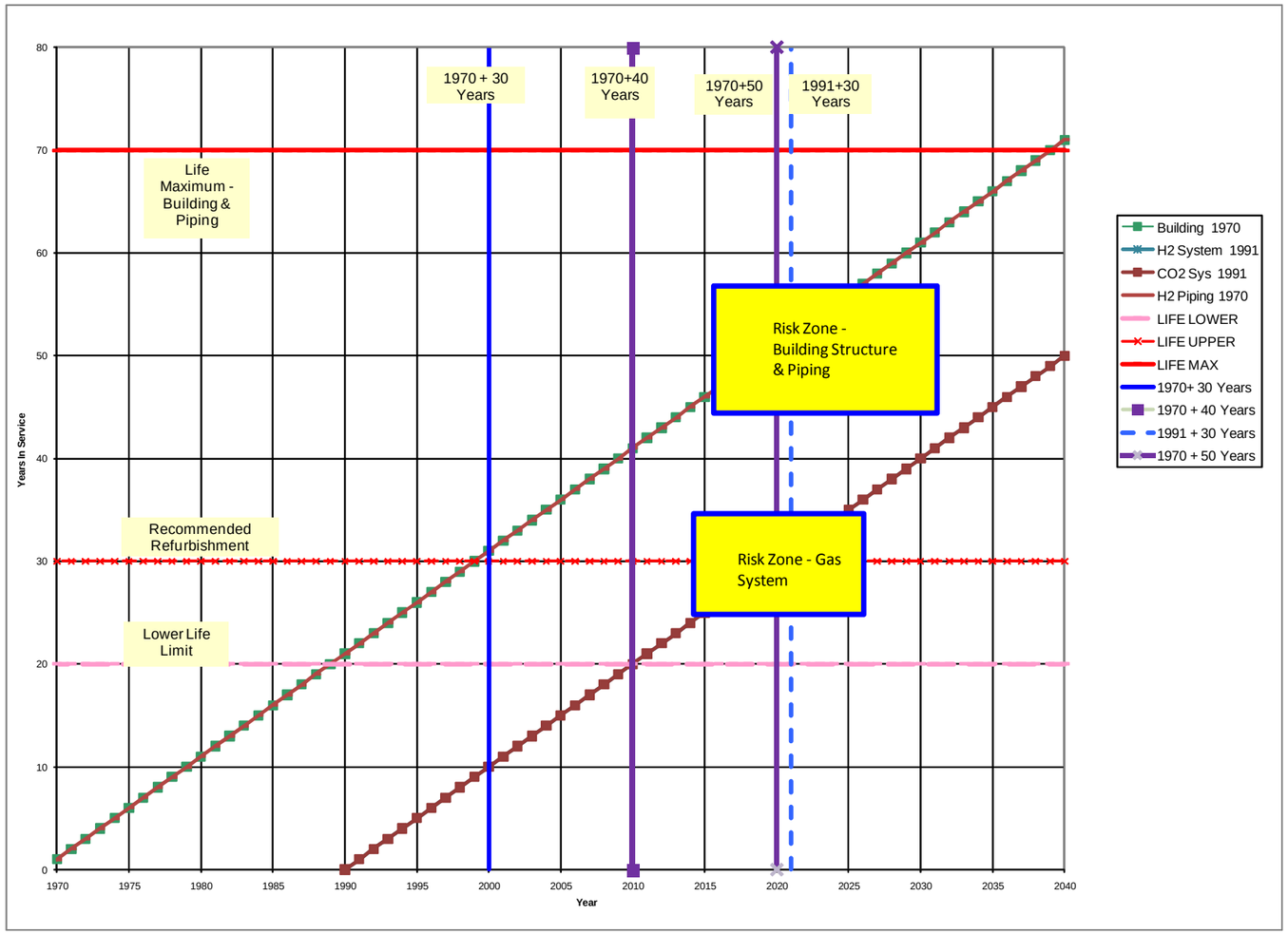



**FIGURE 11-19 LIFE CYCLE CURVE – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

The curves indicates the remaining life (RL) of the hydrogen, nitrogen, and carbon dioxide supply systems exceeds the end date for generation of 2020 but not likely the desired life (DL) which is the end date for synchronous generation of 2041. It is clear that the system generally has considerable technical life remaining. Three concerns not reflected are i) the condition of the distribution piping for which no test information was reviewed, ii) the restricted supply capability of the carbon dioxide delivery system; and iii) the limited supply infrastructure for hydrogen on the mainland.

### 11.1.5.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-24 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-24 LEVEL 2 INSPECTION – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7206 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | N/A | 59 | | Level 2 required - representative tube sampling and thickness tests. | 2011 | 1 | $15 |
| 1297 | 7199 | 7206 | 7236 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | N/A | 60 | | Level 2 required - representative tube sampling and thickness tests. | 2011 | 1 | (Incl in 59) |
| 1297 | 7199 | 7206 | 7237 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | CARBON DIOXIDE STORAGE/SUPPLY | N/A | 61 | | Level 2 required - representative tube sampling and thickness tests. | 2011 | 1 | (Incl in 59) |
| 1297 | 7199 | 7206 | 7238 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | NITROGEN STORAGE/SUPPLY SYSTEM | N/A | 62 | | Level 2 required - representative tube sampling and thickness tests. | 2011 | 1 | (Incl in 59) |

### 11.1.5.8 Capital Projects

The suggested typical capital enhancements for the hydrogen, nitrogen, and carbon dioxide supply systems include:

**TABLE 11-25 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – HYDROGEN, NITROGEN, AND CARBON DIOXIDE SUPPLY SYSTEMS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7206 | 0 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | 60 | 17 | No capital required. | | |
| 1297 | 7199 | 7206 | 7236 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | 61 | 17 | Upgrade to hydrogen storage - LP production & bulk storage. | 2012 | 1 |
| 1297 | 7199 | 7206 | 7237 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | CARBON DIOXIDE STORAGE/SUPPLY | 62 | 17 | No capital required. | | |
| 1297 | 7199 | 7206 | 7238 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | NITROGEN STORAGE/SUPPLY SYSTEM | 63 | 17 | No capital required. | | |

### 11.1.6 Asset 7231 – Compressed Air

(Detailed Technical Assessment in Working Papers, Appendix 10)

| | |
|---|---|
| Unit #: | 1 |
| Asset Class # | BU 1297 - Assets Commons |
| SCI & System: | 7199 HRD Common Systems |
| Sub-Systems: | 7205 Compressed Air Systems |
| Components: | 7231 Compressors<br>7234 Compressed Air Dryers Systems<br>7235 Compressed Air Receivers |

#### 11.1.6.1 Description

| | Stage 1 | Stage 2 |
|---|---|---|
| Manufactured/Delivered | 1969 | 1979 |
| In-Service Date | Sep 1970 | Feb 1980 |
| Generation Base Load End Date | Dec 2015 | |
| Generation Peak/Emerg Gen End Date | Dec 2020 | |
| Synchronous Condensing End Date | Dec 2041 | Dec 2041 |
| Actual/Planned Compressor Replacement | | 2014/2015 |

Compressed air systems are provided for both Stage 1 and Stage 2. The compressors feed the service air system at about 793 kPa (115 psig). A portion of compressed air is drawn from service air receivers and is filtered and dried for use as instrument air. Cooling water is provided from the general service water system for the cooler and aftercooler requirements for each compressor.

Stage 1 Compressor #1 (ZR3-67) is an Atlas Copco oil-free screw compressor. Model number ZR3-67. The compressor is rated at 315 L/s @ 1.05 MPa. It was commissioned in December 1997.

Stage 1 Compressor #2 (ZR3-B) is an Atlas Copco oil-free screw compressor. Model number ZR3-B. The compressor is rated at 310 L/s @ 1.05 MPa. Its commissioning date is uncertain, but likely around 1997.

Stage 2, Compressor #3 (ZR132-VSD) is an Atlas Copco oil-free screw compressor. The compressor is designed to efficiently produce compressed air between 127 and 357 L/s. This compressor uses a variable speed drive for capacity control. It was commissioned in December 2008.

The service air and instrument air pressure vessels for both Stage 1 and Stage 2 are original equipment. The air compressor and Stage 1, Unit 1 instrument air receivers are illustrated below.







**FIGURE 11-20 STAGE 1 COMPRESSOR & INSTRUMENT AIR RECEIVER**

### 11.1.6.2 History - Inspection and Repair History

The service air pressure vessels and instrument air pressure vessels are original equipment, but are inspected annually in accordance with government regulations. Based on information reviewed and on discussions with station staff, no indication of any significant degradation or maintenance/regulatory issues during annual inspections were identified.

The instrument air filtering and drying systems also receive annual maintenance and there is no indication of significant maintenance issues.

### 11.1.6.3 Condition Assessment

The condition assessment of the compressed air system is illustrated below in Table 11-26.

**TABLE 11-26 CONDITION ASSESSMENT – COMPRESSED AIR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7205 | 0 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR SYSTEMS | N/A | 49 | 10 | The service air pressure vessels and instrument air pressure vessels are original equipment, but are inspected annually in accordance with government regulations. Based on discussions with station staff, there has been no indication of any significant degradation. | | | | | | | | | |
| 1297 | 7199 | 7205 | 7231 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | AIR COMPRESSORS | N/A | 50 | 10 | | | | | | | | | | |
| 1297 | 7199 | 7205 | 7231 | 8918 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | N/A | 51 | 10 | Near end of life. | 10 | (20) | 3 | 2041 | 2011 | | Yes | No | 1997 |
| 1297 | 7199 | 7205 | 7231 | 9488 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | N/A | 52 | 10 | Near end of life. | 10 | (20) | 3 | 2041 | 2011 | | Yes | No | 1997 |
| 1297 | 7199 | 7205 | 7231 | 325028 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #3 ATLAS COPCO ROTARY COMP | N/A | 53 | 10 | New in 2008. | 10 | (20) | 20 | 2041 | 2011 | | Yes | No | 2008 |
| 1297 | 7199 | 7205 | 7231 | 99000081 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | BALANCE OF AIR COMPRESSORS SYSTEM | N/A | 54 | 10 | Good condition. No significant issues identified beyond replacement of aging compressors. | 3a | (30) | 15+ | 2041 | 2011 | 2011 | Yes | No | 1968-1979 |
| 1297 | 7199 | 7205 | 7234 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | N/A | 55 | 10 | Instrument air filtering and drying systems receive annual maintenance and are working per requirements. | 3a | (50) | 15+ | 2041 | 2011 | 2011 | Yes | No | 1968-1979 |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | N/A | 56 | 10 | Service and instrument air pressure vessels are original equipment, but are in good shape with no noted degradation. They are inspected annually in accordance with government regulations. | 3a | (50) | 15+ | 2041 | 2011 | 2011 | Yes | No | 1968-1979 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.1.6.4 Actions

Based on the condition assessment, the following actions are recommended for the compressed air system:

**TABLE 11-27 RECOMMENDED ACTIONS – COMPRESSED AIR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7205 | 0 | 0 | COMMON | COMPRESSED AIR SYSTEMS | COMPRESSED AIR | 53 | 10 | Maintain annual inspections of current air dryer and receiver. | 2011 | 1 |
| 1297 | 7199 | 7205 | 7231 | 8918 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | 55 | 10 | Procure and install new air compressors. | 2014 | 1 |
| 1297 | 7199 | 7205 | 7231 | 9488 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | 56 | 10 | Procure and install new air compressors. | 2015 | 1 |
| 1297 | 7199 | 7205 | 7231 | 325028 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #3 ATLAS COPCO ROTARY COMP | 57 | 10 | New in 2008. No Action. | | |
| 1297 | 7199 | 7205 | 7231 | 99000081 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | BALANCE OF AIR COMPRESSORS STA | 58 | 10 | No recommended action. | | |
| 1297 | 7199 | 7205 | 7234 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | 59 | 10 | No recommended action. | | |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | 60 | 10 | No recommended action. | | |

### 11.1.6.5 Risk Assessment

The risk assessment associated with the compressed air system, both from a technological perspective and a safety perspective, is illustrated below in Table 11-28.

**TABLE 11-28 RISK ASSESSMENT – COMPRESSED AIR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7205 | 0 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR SYSTEMS | None | 50 | 10 | See details below. | | N/A | | | | | | | | |
| 1297 | 7199 | 7205 | 7231 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | AIR COMPRESSORS | None | 51 | | See details below. | | N/A | | | | | | | | |
| 1297 | 7199 | 7205 | 7231 | 8918 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | Air Compressor failure –original units | 52 | 10 | Mechanical fatigue. | 3 | near EOL | 3 | B | Medium | 3 | B | Low | Loss air – interconnected, minimal, but increased risk of further failure. | Replace. |
| 1297 | 7199 | 7205 | 7231 | 9488 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | Air Compressor failure –original units | 53 | 10 | Mechanical fatigue. | 3 | near EOL | 3 | B | Medium | 3 | B | Low | | Replace. |
| 1297 | 7199 | 7205 | 7231 | 325028 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #3 ATLAS COPCO ROTARY COMP | Air Compressor failure –newer unit | 54 | 10 | Mechanical fatigue. | 20 | N/A | 1 | B | Low | 1 | B | Low | Loss air – interconnected, minimal. | Inspect, maintain. |
| 1297 | 7199 | 7205 | 7234 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | Air Dryers | 56 | 10 | Corrosion, mechanical failure. | 15+ | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7205 | 7234 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | Air Dryers | 57 | 10 | Corrosion, mechanical failure. | 15+ | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | Air Receivers – Service Air | 58 | 10 | Corrosion, mechanical failure. | 20 | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | Air receivers – Instrument Air | 59 | 10 | Corrosion, mechanical failure. | 20 | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | Air Receivers – Service Air | 60 | 10 | Corrosion, mechanical failure. | 20 | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | Air receivers – Instrument Air | 61 | 10 | Corrosion, mechanical failure. | 20 | N/A | 1 | A | Low | 1 | C | Low | Loss air – interconnected. | Annual and regulatory inspect and maintain. |

### 11.1.6.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of current and projected unit operating hours of usage on the y-axis versus calendar year on the x-axis. The unit operating hours is used as a substitute for actual compressor hours data not available. In these cases only one operating hours scenario is illustrated post 2009 to minimize the confusion. It includes hours for both generating mode and synchronous condensing mode (assuming modification in 2014). The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating hour life limits. The risk area boxes provide an indication of the timing of potential issues either from an age or equivalent operating hours view.

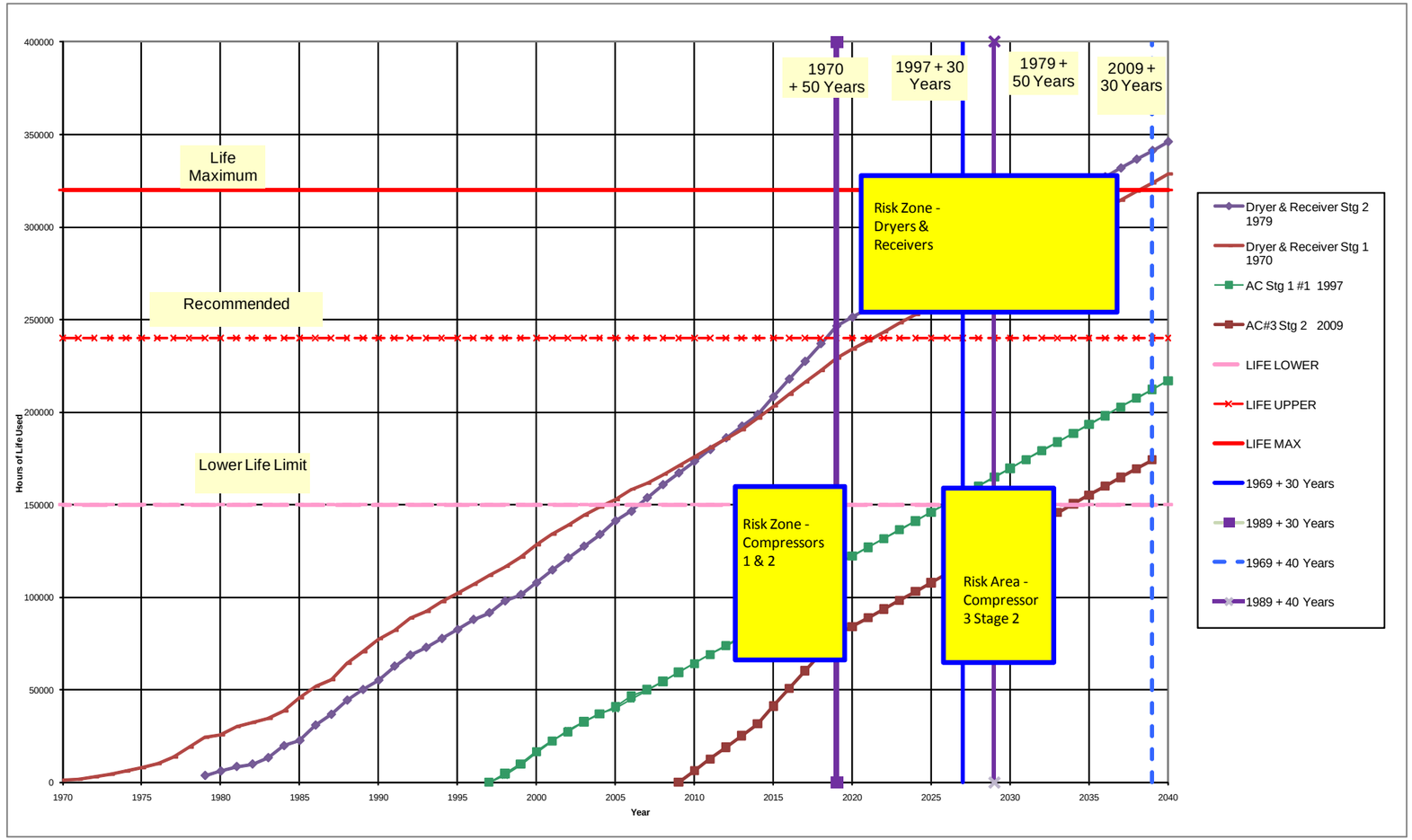



**FIGURE 11-21 LIFE CYCLE CURVE – COMPRESSED AIR**

The curves indicate that the remaining life (RL) of the compressed air system exceeds the end date for generation of 2020, but maybe not the desired life (DL) of 2041 (at the end of synchronous condensing life) without refurbishment and/or replacement. The exception is the current stage 1 compressors which are in need of replacement in the next few years and the newer Stage 2 compressors which will likely need replacement in the period after 2020.

### 11.1.6.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-29 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-29 LEVEL 2 INSPECTION – COMPRESSED AIR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7205 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR SYSTEMS | | 49 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7231 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | AIR COMPRESSORS | N/A | 50 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7231 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | N/A | 51 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7231 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | N/A | 52 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7231 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | ATLAS COPCO ROTARY COMP | N/A | 53 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7231 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | BALANCE OF AIR COMPRESSORS STA | N/A | 54 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7234 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | N/A | 55 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |
| 1297 | 7199 | 7205 | 7235 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | N/A | 56 | 10 | No Level 2 analyses is required, provided the current inspection and maintenance program is maintained. | | | |

### 11.1.6.8 Capital Projects

The suggested typical capital enhancements for the compressed air system include:

**TABLE 11-30 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – COMPRESSED AIR**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7205 | 0 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR SYSTEMS | 50 | 10 | No capital required. | | |
| 1297 | 7199 | 7205 | 7231 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | AIR COMPRESSORS | 51 | 10 | No Capital | | |
| 1297 | 7199 | 7205 | 7231 | 8918 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | 52 | 10 | Replace compressor. | 2014 | 1 |
| 1297 | 7199 | 7205 | 7231 | 9488 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | 53 | 10 | Replace compressor. | 2015 | 1 |
| 1297 | 7199 | 7205 | 7231 | 325028 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | ATLAS COPCO ROTARY COMP | 54 | 10 | No capital required. | | |
| 1297 | 7199 | 7205 | 7231 | 99000081 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | BALANCE OF AIR COMPRESSORS STA | 55 | 10 | No capital required. | | |
| 1297 | 7199 | 7205 | 7234 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR DRYERS SYSTEMS | 56 | 10 | No capital required. | | |
| 1297 | 7199 | 7205 | 7235 | 0 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | COMPRESSED AIR RECEIVERS | 57 | 10 | No capital required. | | |

## 11.2 Common Systems - Lower Priority Systems

### 11.2.1 Assets 7209 and 7204 – Fuel Systems (Light and Heavy Oil)

(Detailed Technical Assessment in Working Papers, Appendix 27)

| | |
|---|---|
| Unit #: | Common |
| Asset Class # | BU 1297 - Assets Common |
| SCI & System: | 7199 HRD Common Systems |
| Sub-Systems: | 7204 Heavy Oil & Fuel Additive |
| | 7209 Light Oil System |
| Components: | 7223 Heavy oil Transfer to Storage |
| | 7224 Heavy Oil Storage & Piping |
| | 271814 HRD Tank Farm Dykes & Liners |

#### 11.2.1.1 Description

| | **Stage 1** | **Stage2** |
|---|---|---|
| Manufactured/Delivered | 1969 | 1979 |
| In-Service Date | Sep 1970 | Feb 1980 |
| Refurbishment – Heavy Oil | Tanks 2008 to 2012;<br>Civil/Supports: last 5 Yrs | |
| Refurbishment – Light Oil System | Tanks in last 5 years | |
| Base Load Requirement End Date | Dec 2015 | |
| Boiler Use End Date (Light/Heavy) | Dec 2020 | |
| Requirement – GTG Use End Date | Dec 2020 | |

**Heavy Oil System**

**Heavy Oil Main Storage Tanks:** Holyrood has 4 large heavy oil storage tanks that store the sites' supply of No. 6 fuel oil. Oil is piped to tanks from ships at the marine terminal. Tanks 1 and 2 were installed in 1969 and tanks 3 and 4 in 1977. Each tank is 55 m (180 feet) in diameter and 14.6 m (48 feet) high with a capacity of 31.6 million litres (200,000 bbl). Tanks are made of carbon steel and have an interior coating that functions to slow the rate of corrosion.

The residual oil that is supplied from any of the 4 main heavy fuel oil storage tanks flows to the fuel oil day tank. The main fuel oil is gravity fed from both the main fuel oil storage tanks to the day tanks as well from the day tank to the unit main heavy oil pumping and heating station.




FIGURE 11-22 HEAVY OIL MAIN STORAGE TANKS




FIGURE 11-23 HEAVY OIL – PIPING FROM STORAGE TO POWERHOUSE

**Heavy Oil Day Tanks:** The heavy oil day tank is approximately 12 to 15 years old. It has a rubber lined floor. The capacity was increased from 57 to 114 million litres (2000 to 4000 bbls) in 1980's. The piping layout for Unit 3 heavy oil system includes the use of a "short" recirculation valve which is piped back to the fuel oil day tank allowing the heavy oil pumps to be in service with the main oil trip valve closed. A "main fuel oil recirculation valve" and line is provided just upstream of the main oil trip valve and is used to re-circulate the oil back to the day tank.





**FIGURE 11-24 HEAVY OIL DAY TANK AND PIPING TO POWERHOUSE**

**Heating Systems:** The viscosity (SSU) of No. 6 fuel oil is high and hence requires heat for it to flow. Electric heat tracing is provided on the 46 cm (18 inch) pipeline from the receiving dock to the main oil tank farm.

Each storage tank is equipped with steam heat exchangers to enable the oil to gravity flow from the tanks to the main fuel oil lines.

Steam heat tracing is provided on all the main fuel oil lines feeding both the fuel oil day tank and the unit pumping and heating set.

**Miscellaneous:** The heavy oil system includes a magnesium oxide (MgO) fuel oil additive system (skids, tank), but the requirement for the system has been minimized since the lower sulphur oil has been used. This system is not specifically addressed.



**FIGURE 11-25 FUEL ADDITIVE STORAGE TANK**

**Light Oil System**

Light oil (#2 fuel oil) is used for diesel gensets, the black start gas turbine, and main unit ignition oil. It is gravity fed from the light oil fuel oil tanks.

Oil is received at the side of the black start diesel building and transferred to two 100,000 litre light oil tanks. There is very obvious corrosion pitting of the receiving lines and valves. The light oil pressure at the main units is maintained through constant recirculation back to the light oil storage tanks through a pressure control valve and piping arrangement.

The tanks themselves are relatively new (5 to 6 years). The lines under the roadway have been replaced as part of road repair work carried out in 2007.




**FIGURE 11-26 LIGHT OIL RECEIVING SYSTEM AND STORAGE TANKS**

### 11.2.1.2 History - Inspection and Repair History

A review of the 2006 SGE Acres report "Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Diced Drainage System Holyrood Thermal Generating Station" was used to determine the existing condition of the tanks in conjunction with a walkthrough of the tank farm.

**Heavy Oil Main Storage Tanks:** Tank inspections were last undertaken and the remaining life of the tanks estimated at the time as follows:

| Tank # | Inspection Date | Remaining Floor Life |
|---|---|---|
| 1 | Dec 2005 | 10 years |
| 2 | Oct 19987 | Not estimated. Next planned inspection was scheduled for 2008, but no indication it was carried out. |
| 3 | Nov 2003 | 5-6 years |
| 4 | Aug 2004 | 5-6 years |

These led to the current tank refurbishment program to extend the life of the tanks by at least 20 years. The main issues with the tanks tended to be roof and floor repairs.

Tank Refurbishment Plan

- #4 tank bottom replacement - 2010
- #3 tank bottom replacement - 2011
- #1 tank bottom - 2012
- #2 tank refurbishment - 2008

The timing of inspections associated with API 653 and regulatory requirements are planned to continue.

A great deal of upgrade work has been recently undertaken with regard to the tank farm auxiliaries and areas – dykes, retention area drainage, pipe supports, pipe insulation and heat tracing (steam heat tracing from tanks to station). As a result, all are expected to be in good condition.

**Heavy Oil Day Storage Tank:** The heavy oil day tank is 12 years old. It has a rubber lined floor. No information was available on past inspections or on the condition of the tank. Given its age, it is assumed the tank is still in reasonable condition, however a condition assessment, whether a Level 2 or an API inspection, is warranted as soon as practical.

**Heavy Oil Electric Trace Heating:** Electric heat tracing is provided on the 46 cm (18 inch) pipeline from the receiving dock to the main oil tank farm. The electric heat tracing system has failed, and though repair work has been able to restart 2 of the 3 phases, they could fail anytime. An immediate repair or replacement is necessary.

**Heavy Oil Steam Trace Heating:** The heavy oil steam trace heating system on the pipeline in and from the tank farm to the powerhouse and day tank have been refurbished (along with civil supports) in last few years. It is operating well and in good condition.

**Heavy Oil Heating & Pumping:** The in-plant heavy oil heating and pumping systems receive regular maintenance and inspections. No specific information was reviewed on their condition, but maintenance discussions and visual inspections (limited) indicate that they appear to be in reasonable condition, given their service and age.

**Light Oil Storage Tanks & Receiving System:** The light oil storage tanks are relatively new (approximately 5 years old). The lines under the roadway have been replaced as part of road repair work carried out in 2007. Inspection information was not considered given the relatively short duration since their in-service date. They are subject to API regulatory inspection requirements.

The light oil receiving, pumping and piping system located at the gas turbine building are operational, but have experienced significant external corrosion due to the marine environment, including the lines to the light oil storage tanks and to the powerhouse ignition oil system. No data on inspections or testing was available during the study to indicate the extent of the corrosion or possible remaining life.

### 11.2.1.3 Condition Assessment

The condition assessment of the fuel systems (light and heavy oil) is illustrated below in Table 11-31.

**TABLE 11-31 CONDITION ASSESSMENT – FUEL SYSTEMS (LIGHT AND HEAVY OIL)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 0 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL & FUEL ADDITIVE | N/A | 33 | 27 | Not addressed. Out of service. | | | | | | | | | |
| 1297 | 7199 | 7204 | 7223 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | *HEAVY OIL TRANSFER TO STORAGE | N/A | 34 | 27 | Electric heat tracing system on the heavy oil delivery line from the dock to tank farm area has failed. Bootstrapped to work on two of three phases. Needs immediate redesign and repair/replacement. | 4 | (30) | 1 | 2020 | | | No | No | 2000 |
| 1297 | 7199 | 7204 | 7224 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | N/A | 35 | 27 | Steam heat tracing from tank farm to the plant day tank has been upgraded. Steam heat tracing in the plant day tank area is functional but leaking. | 4 | 200000 (30) | 15+ | 2020 | | | Yes | Yes | 2009 |
| 1297 | 7199 | 7204 | 7224 | 7439 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL DAY TANK | N/A | 36 | 27 | 12 years old. No information was available on past inspections and the condition of the tanks. | 4 | (40) | (15+) | 2020 | 2011 | 2011 | Yes | No | 1988 |
| 1297 | 7199 | 7204 | 7224 | 7441 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | N/A | 37 | 27 | Major tank refurbishment to extend by 20+ years, primarily roof and floor. | 4 | (40) | 20 | 2020 | 2010 | 2020 | Yes | Yes | 2011 |
| 1297 | 7199 | 7204 | 7224 | 7442 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #2 TANK | N/A | 38 | 27 | Major tank refurbishment to extend by 20+ years, primarily roof and floor. | 4 | (40) | 20 | 2020 | 2011 | 2020 | Yes | Yes | 2012 |
| 1297 | 7199 | 7204 | 7224 | 7443 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #3 TANK | N/A | 39 | 27 | Major tank refurbishment to extend by 20+ years, primarily roof and floor. | 4 | (40) | 20 | 2020 | 2012 | 2021 | Yes | Yes | 2012 |
| 1297 | 7199 | 7204 | 7224 | 7444 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | N/A | 40 | 27 | Major tank refurbishment to extend by 20+ years, primarily roof and floor. | 4 | (40) | 20 | 2020 | 2012 | 2021 | Yes | Yes | 2010 |
| 1297 | 7199 | 7204 | 286055 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | FUEL ADDITIVE SYSTEMS | N/A | 41 | 27 | Not addressed. Out of service. | | | | | | | | | |
| 1297 | 7199 | 7204 | 286055 | 7227 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | F/A STORAGE TANK & PUMPS | N/A | 44 | 27 | Not addressed. Out of service. | | | | | | | | | |
| 1297 | 7199 | 7209 | 0 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | N/A | 45 | 27 | Receiving and delivery system corroded. No data on inspections or testing available. The lines under the roadway replaced in 2007. No inspection information on lines in powerhouse available. | 4 | (40) | (2) | 2041 | 2011 | | No | No | 1968/2007 |
| 1297 | 7199 | 7209 | 99034713 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | 46 | 27 | Relatively new, about 5 to 6 years. No inspections. | 3a | (40) | 10+ | 2041 | 2011 | | No | No | 2004 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

#### 11.2.1.4 Actions

Based on the condition assessment, the following actions are recommended for the fuel systems (light and heavy oil):

**TABLE 11-32 RECOMMENDED ACTIONS – FUEL SYSTEMS (LIGHT AND HEAVY OIL)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 0 | 0 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL & FUEL | 36 | 27 | No recommended action. | | |
| 1297 | 7199 | 7204 | 7223 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | *HEAVY OIL TRANSFER TO STORAGE | 37 | 27 | Undertake design work and replacement of the electric trace heating system from the dock unloading to the storage tanks. | 2010 | 1 |
| 1297 | 7199 | 7204 | 7224 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | 38 | 27 | Continue with external inspections of each tank approximately every 3 to 5 years and internally per corrosion determination but less than 20 years. Complete all recommendations that stem from inspection reports. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7439 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL DAY TANK | 39 | 27 | Perform heavy oil day tank inspection as per API 653 requirements. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7441 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | 40 | 27 | Continue the main fuel oil storage tank upgrade program. | 2012 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7442 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #2 TANK | 41 | 27 | None. Done in 2008. | 2008 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7443 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #3 TANK | 42 | 27 | Continue the main fuel oil storage tank upgrade program. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7444 | COMMON | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | 43 | 27 | Finish the main fuel oil storage tank upgrade. | 2010 | 1 |
| 1297 | 7199 | 7209 | 0 | 0 | COMMON | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | 44 | 27 | See details below. | | |
| 1297 | 7199 | 7209 | 99034713 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | 45 | 27 | Perform Level 2 inspections on light oil storage receiving and handling system and external tank inspection (per API653). | 2011 | 1 |
| 1297 | 7199 | 7209 | 99034713 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | 46 | 27 | Continue with external inspections of each tank approximately every 3 to 5 years and internally per corrosion determination but less than 20 years. Complete all recommendations that stem from inspection reports. | 2011 | 1 |
| 1297 | 7199 | 7204 | 286055 | 0 | COMMON | HEAVY OIL & FUEL ADDITIVE | FUEL ADDITIVE SYSTEMS | 47 | 27 | No recommended action. | | |
| 1297 | 7199 | 7204 | 286055 | 6991 | COMMON | HEAVY OIL & FUEL ADDITIVE | #1 BOILER FUEL ADDITIVE | 48 | 27 | No recommended action. | | |
| 1297 | 7199 | 7204 | 286055 | 6991 | COMMON | HEAVY OIL & FUEL ADDITIVE | MODIFY FUEL ADDITIVE | 49 | 27 | No recommended action. | | |
| 1297 | 7199 | 7204 | 286055 | 7227 | COMMON | HEAVY OIL & FUEL ADDITIVE | F/A STORAGE TANK & | 50 | 27 | No recommended action. | | |

### 11.2.1.5 Risk Assessment

The risk assessment associated with the fuel systems (light and heavy oil), both from a technological perspective and a safety perspective, is illustrated below in Table 11-33.

**TABLE 11-33 RISK ASSESSMENT – FUEL SYSTEMS (LIGHT AND HEAVY OIL)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 0 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL & FUEL ADDITIVE | None | 33 | 27 | Not addressed - out of service. | | N/A | | | | | | | | |
| 1297 | 7199 | 7204 | 7223 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | *HEAVY OIL TRANSFER TO STORAGE | Heavy Oil Steam Trace | 34 | 27 | Mechanical corrosion failure. | 10+ | N/A | 1 | C | Low | 1 | A | Low | Leak – shutdown for repair. | Inspect and maintain. |
| 1297 | 7199 | 7204 | 7224 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | Heavy Oil Steam & Electric Ht Trace | 35 | 27 | Electrical or mechanical. | 1 | Failed state. Needs replacement. Critical to plant viability and reliability | 4 | D | High | 4 | A | Low | Inability to deliver oil. Plant would subsequently have to shut down. Major repair. | Inspect and replace as soon as possible. |
| 1297 | 7199 | 7204 | 7224 | 7439 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL DAY TANK | Heavy Oil Day Tanks | 36 | 27 | Corrosion. | 10+ | N/A | 1 | C | Low | 1 | A | Low | Unit shutdown – bypass possible for repairs. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7204 | 7224 | 7441 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | Heavy Oil Main Tanks | 37 | 27 | Corrosion. | 10+ | N/A | 1 | B | Low | 1 | A | Low | Oil leak – containment overflow. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7204 | 7224 | 7442 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #2 TANK | Heavy Oil Main Tanks | 38 | 27 | Corrosion. | 10+ | N/A | 1 | B | Low | 1 | A | Low | Oil leak – containment overflow. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7204 | 7224 | 7443 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #3 TANK | Heavy Oil Main Tanks | 39 | 27 | Corrosion. | 10+ | N/A | 1 | B | Low | 1 | A | Low | Oil leak – containment overflow. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7204 | 7224 | 7444 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | Heavy Oil Main Tanks | 40 | 27 | Corrosion. | 10+ | N/A | 1 | B | Low | 1 | A | Low | Oil leak – containment overflow. | Annual and regulatory inspect and maintain. |
| 1297 | 7199 | 7209 | 0 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | Light Oil Receiving System | 45 | 27 | Mechanical failure/leaks. | (2) | N/A | 3 | B | Medium | 3 | B | Medium | Unit shutdown for repairs. GTG shutdown for repairs. | Inspect and refurbish/replace. |
| 1297 | 7199 | 7209 | 0 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | Light Oil Piping to station | 46 | 27 | Mechanical failure/leaks. | (2) | N/A | 2 | B | Low | 2 | B | Medium | Unit shutdown for repairs. | Inspect and refurbish/replace. |
| 1297 | 7199 | 7209 | 99034713 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | Light Oil Tanks | 47 | 27 | Mechanical failure/leaks. | 10+ | N/A | 1 | A | Low | 1 | A | Low | Unit shutdown for repairs. | Annual and regulatory inspect and maintain. |

### 11.2.1.6 Life Cycle Curve and Remaining Life

The life cycle curves for the oil systems are illustrated below. Two figures are used - one for the heavy oil and light oil tanks and the other for the heavy and light oil BOP. Several curves are required to represent the various elements of and their operational timing. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. For this system the actual life may only need to extend to 2020, although the curves are continued to 2041.The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

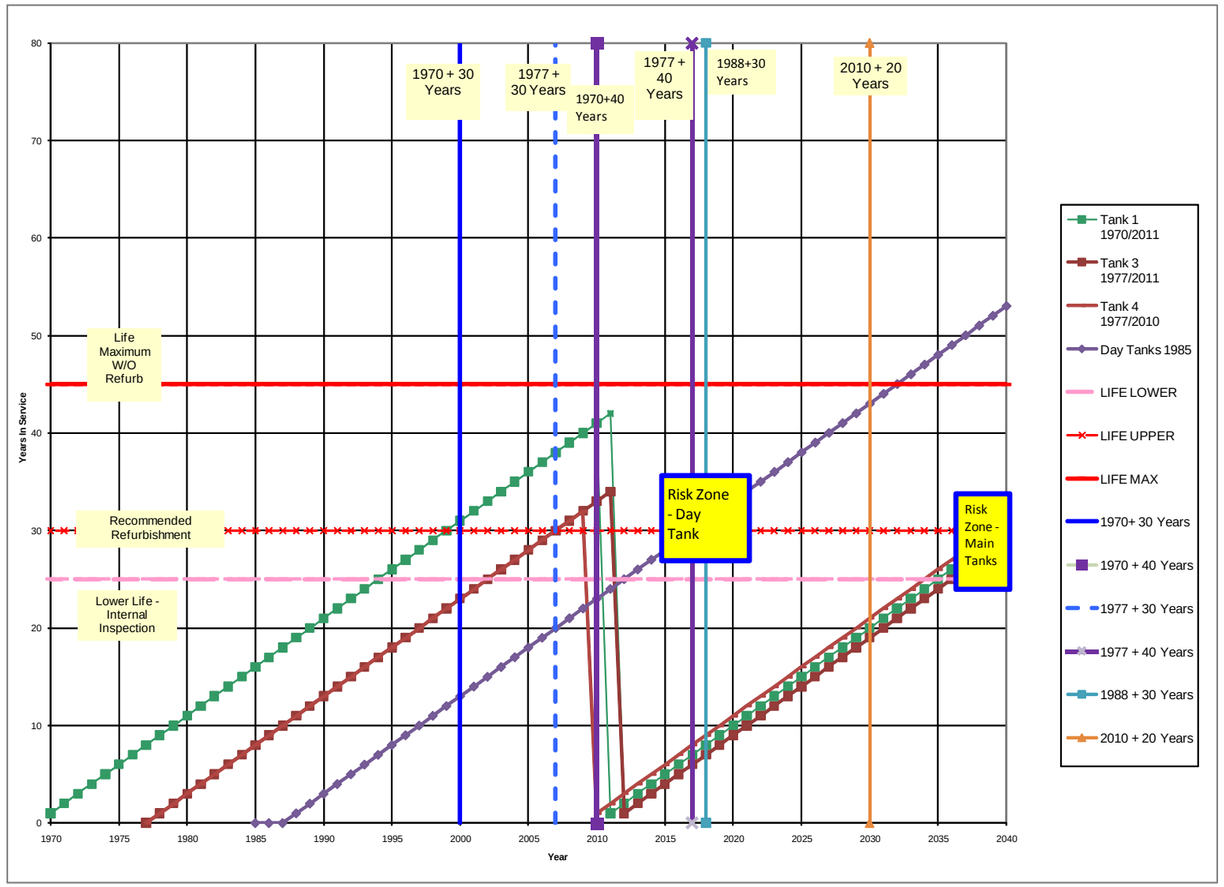



**FIGURE 11-27 LIFE CYCLE CURVE – FUEL SYSTEMS (LIGHT AND HEAVY OIL TANKS)**

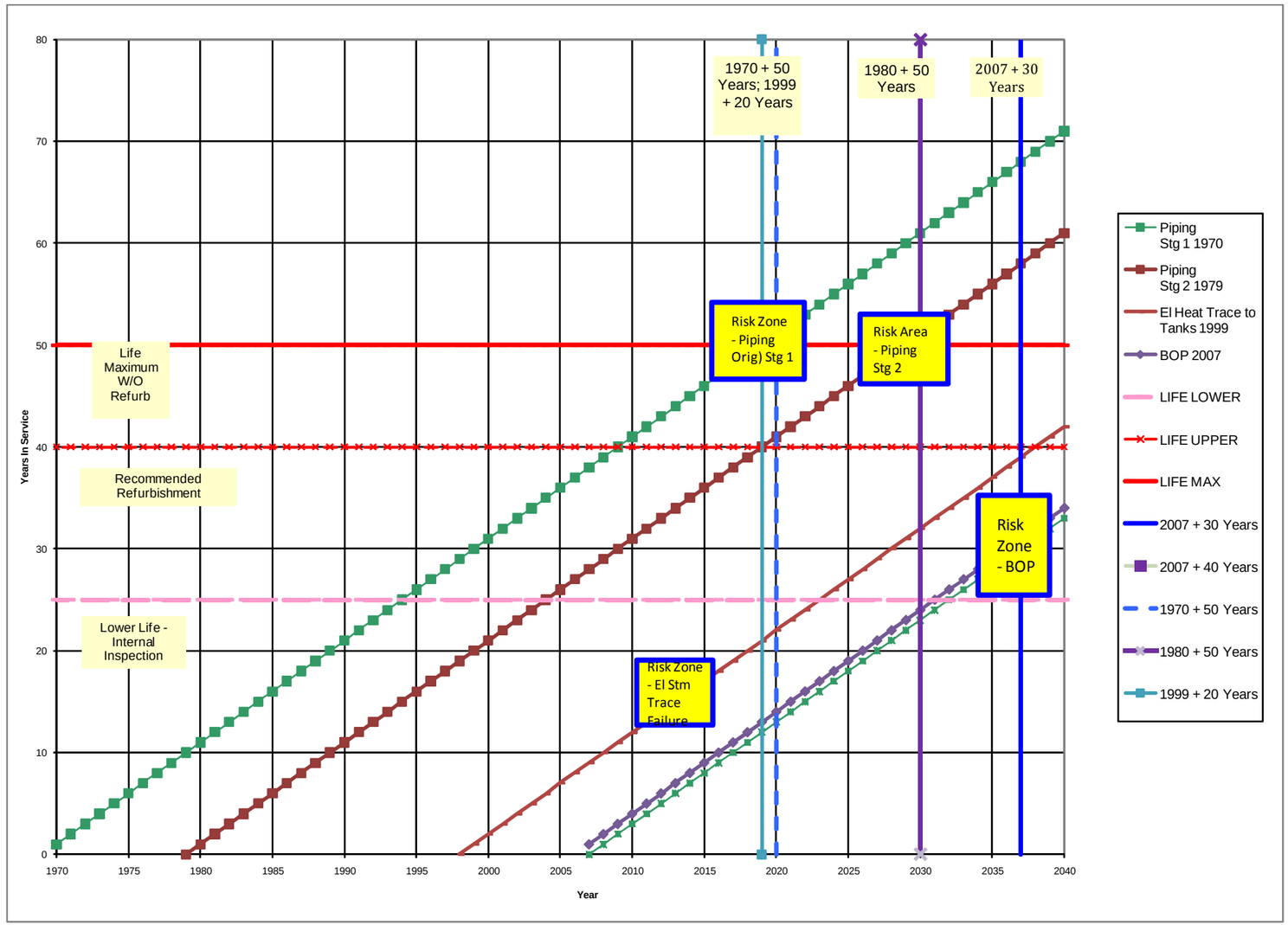



**FIGURE 11-28 LIFE CYCLE CURVE – FUEL SYSTEMS (LIGHT AND HEAVY OIL - BOP)**

The curves indicate that the remaining life (RL) of the light oil and heavy oil tanks can reach the desired life (DL) of the end date for generation of 2020 once the current heavy oil tank refurbishment is completed. It does identify a need for the heavy oil day tank to be inspected and refurbished in the near future. It also identified the immediate and critical problem of the electric heat tracing on the oil delivery line to the heavy oil tank farm.

### 11.2.1.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-34 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-34 LEVEL 2 INSPECTION – FUEL SYSTEMS (LIGHT AND HEAVY OIL)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL & FUEL ADDITIVE | N/A | 33 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 7223 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL TRANSFER TO STORAGE | N/A | 34 | 27 | Replacement assessment | 2010 | 1 | $73 |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | N/A | 35 | 27 | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL DAY TANK | Heavy oil Tanks | 36 | 27 | API 653 internal inspection of heavy oil day tank, unless already done, by 2012 | 2012 | 1 | $37 |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | N/A | 37 | 27 | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #2 TANK | N/A | 38 | 27 | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - TANK | N/A | 39 | 27 | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | N/A | 40 | 27 | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 286055 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | FUEL ADDITIVE SYSTEMS | N/A | 41 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 286055 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | #1 BOILER FUEL ADDITIVE SYSTEM | N/A | 42 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 286055 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | MODIFY FUEL ADDITIVE SYSTEM, S | N/A | 43 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7204 | 286055 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | F/A STORAGE TANK & PUMPS | N/A | 44 | N/A | No Level 2 required. | | | |
| 1297 | 7199 | 7209 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | Light Oil receiving & handling | 45 | 27 | Level 2 inspection of light oil receiving and forwarding pumps, valves, and piping - See GTG. | | | |
| 1297 | 7199 | 7209 | 99034713 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | Light Oil Tanks | 46 | 27 | API 653 external inspection of light oil tanks . | 2012 | 1 | (Incl in 36) |

### 11.2.1.8 Capital Projects

The suggested typical capital enhancements for the fuel systems (light and heavy oil) include:

**TABLE 11-35 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – FUEL SYSTEMS (LIGHT AND HEAVY OIL)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 0 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL & FUEL ADDITIVE | 34 | 27 | No capital required. | | |
| 1297 | 7199 | 7204 | 7223 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | *HEAVY OIL TRANSFER TO STORAGE | 35 | 27 | Replace electric heat trace system. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 0 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | 36 | 27 | No capital required. | | |
| 1297 | 7199 | 7204 | 7224 | 7439 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL DAY TANK | 37 | 27 | No capital required. | | |
| 1297 | 7199 | 7204 | 7224 | 7441 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | 38 | 27 | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2012 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7442 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #2 TANK | 39 | 27 | No capital required. | | |
| 1297 | 7199 | 7204 | 7224 | 7443 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #3 TANK | 40 | 27 | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7444 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | 41 | 27 | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2010 | 1 |
| 1297 | 7199 | 7209 | 0 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | LIGHT OIL SYSTEM | 46 | 27 | No capital required. Piping associated with gas turbine is a priority and is addressed as part of gas turbine package. | | |
| 1297 | 7199 | 7209 | 99034713 | 0 | COMMON SYSTEMS | LIGHT OIL SYSTEM | OIL STORAGE TANK | 47 | 27 | No capital required. | | |

### 11.2.2 Waste Water Treatment Plant (WWTP)

(Detailed Technical Assessment in Working Papers, Appendix 16)

| | |
|---|---|
| Unit #: | Common Facilities |
| Asset Class # | BU 1297 - Assets Common |
| SCI & System: | 9739 HRD Waste Water Treatment & Environment |
| Sub-Systems: | 10038 HRD Waste Water Treatment Plant |
| Components: | 286057 Waste Water Treatment Plant Systems |
| Components: | 7263 Oil/Water Separators |

The following buildings are addressed in the Buildings section in Section 11.1.4.

| | |
|---|---|
| Unit #: | Buildings |
| Asset Class # | BU 1297 - Assets Common |
| SCI & System: | 72559739 HRD Buildings & Site |
| Sub-Systems: | 272255 HRD Buildings |
| Components: | 7304 Waste Water Treatment Plant Building |
| | 7305 Waste Water Treatment Basins Building |

#### 11.2.2.1 Description

The waste water treatment facility is common to the whole plant:

| | |
|---|---|
| Installed Waste Water Treatment Basins | 1992 |
| Installed New Waste Water Treatment Plant | 1994 |
| Upgraded Process Plant (filter press) | 2002 |
| Generation Base Load End Date | Dec 2015 |
| Generation Peak/Emerg Gen End Date | Dec 2020 |
| Synchronous Condensing End Date | Dec 2041 (Lower Usage required) |

The hours (anticipated maximum operating hours associated with 3 units) associated with the analyses are:

| | |
|---|---|
| Hours Generation Actual – 1994/2002 to Dec 2009 | 74,000/32,000 |
| Max Hrs Ops to Gen End Date Dec 2015 | 104,000/62,000 |
| Max Hours Ops – to Gen End Date - Dec 2020 | 127,000/85,000 |
| Max Hrs Ops to SC End Date Dec 2041 | 220,000/185,000 |

The WWT plant will be required to process plant run-off and other site waste water year round up to the year 2041. The WWTP treats the wastewater generated at the plant, including Unit 1, Unit 2 and Unit 3, as well as common areas.

The WWTP building is a pre-engineered steel building that sits on a concrete foundation.

The waste water equalization basin building covers two large tanks. It is a pre-engineered steel building that sits on a concrete foundation with two large open concrete tanks that occupy the majority of the building. The tanks receive drainage water from the power plant. One tank holds “cleaner” water while the other tank holds contaminated water (boiler blowdown, boiler cleans, etc.). Contaminated water is fed into the WWTP where it is treated and then released into the environment. The cleaned water is then released directly into the environment when the water level reaches a certain elevation in the tank.

The WWTP process includes the following major equipment elements:

- Oil/water separator
- Equalization basins
- Mechanical settler
- Solids filter press

Collected solids from the WWTP and its processes are transported to the on-site landfill for final disposal. Cleaned water is released.

**Waste Water Treatment Plant (WWTP) Batch Reactor & Building:** The WWTP process equipment was installed in a separate building in 1994. It consists of a batch stirred reactor and a filter press. As a result, the mechanical filter is about 16 years old and the filter press less than 10 years.

**Waste Water Treatment Plant Treatment Basin & Building:** The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The two settling ponds serve dirty sources and cleaner sources respectively. No automated treatment is installed, but the pH is addressed periodically. The basins are hard concrete built on bedrock.

**Oily Water Separator and Piping:** Four buried passive oily-water separation tanks were installed in 1991 between the power plant and the waste water basins. The tanks are coated internally and are expected to remove the oil from waste water flowing to the treatment basin ponds

**Waste Water Piping:** Waste water from the site is routed to the WWTP basins. In the powerhouse there are two sump pits (between Units 1 and 2 and one near Unit 3). Normally waste water is collected in the sump pits and is pumped via 63 mm CPVC underground lines to the WWTP basins. Several manholes and flushing connections are located between the sumps and the WWTP basins. Periodic drainage for air preheater washes, fireside boiler washes or boiler acid cleans is handled using temporary piping to the basins.

#### 11.2.2.2 History - Inspection and Repair History

**Waste Water Treatment Plant (WWTP) Batch Reactor & Building:** The WWTP is about 16 years old and the filter press less than 10 years. Although no major inspections were identified as having been undertaken, it was clear from staff interviews and from a high level visual inspection when the settling tank and its auxiliaries were empty that the equipment is in good condition.

Until approximately 2007, these systems were in continuous use due to the frequency of boiler cleans during operational seasons. Since 2007, less boiler cleanup water has meant there is more time to access the mechanical settler and filter press for maintenance and inspection. Overall the entire system

has had considerably less operation since the adoption of the new fuel oil which has required less boiler and airpreheater washes.

The building is structurally sound. The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies were noted. It does have some rusty siding.

**Waste Water Treatment Plant Treatment Basin & Building:** The two WWTP treatment basins and their building enclosure were built in 1992 to address effluent concerns. The basins are cleaned out approximately on a one to two year frequency. The last inspection was identified as being in 2007/2008 and one minor crack was identified, but no detailed examination has been completed.

There are some OHSA air quality concerns by staff and safety issues around basin access (exit routes). Some initial assessment on replacement of the roof and exhaust fans, as well as some side wall ventilation, was considered for 2011 at a cost of about $800k-$1M.

A walkthrough of the equalization basin building was performed to gauge the existing condition of the building. It was clear both the interior and exterior have been affected by the very humid atmosphere. Ventilation systems have not been very effective and have experienced corrosion. The roofing is considered by staff to be unsafe. Improved oily surface skimming and basin pond egress is considered desirable. The structural steel has also experienced significant rusting.

**Oily Water Separator and Piping:** The four buried passive oily-water separation tanks are periodically inspected, but typically only visually. They are expected to remove the oil from waste water flowing to the treatment basin ponds. It was evident from an oily sheen on the surface of the water in the WWTP basin during visual walkdowns that this is not always the case.

The last inspection of one of the tanks was less than five years ago, but no report was available. The tanks are identified as being in reasonably good shape, although there was some internal corrosion. No specific NDE testing was undertaken.

**Site Waste Water Piping:** Staff interviews identified a concern that not all of the plant drains are draining properly and may have breaks or blockages. No specific inspection documentation was available that indicated the condition of the underground waste water piping. Some of it is assumed to be original equipment and some presumably has only been in place since the WWTP in-service date of 1994. It is generally expected to be in good shape, but there is some concern that leakage might be occurring.

### 11.2.2.3 Condition Assessment

The condition assessment of the waste water treatment plant is illustrated below in Table 11-36.

**TABLE 11-36 CONDITION ASSESSMENT – WASTE WATER TREATMENT PLANT (WWTP)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | N/A | 154 | 16 | Process equipment installed in 1994 and new filter press in the past ten years. No major inspections have been undertaken, but interviews and visual inspection indicate it is in good shape. | 3a | (30) | 20 | 2041 | | | Yes | No | 1994/2000 |
| 1297 | 9739 | 10038 | 7263 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | N/A | 155 | 16 | Basin water oil suggest separators are not always effective. Some concerns that some plant drains may have breaks or blockages. No specific inspection documentation was available that indicated the state of the lines. | 4 | (30) | (10+) | 2041 | | | No | No | 1991 |
| 1297 | 9739 | 10038 | 99003527 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | CONCRETE BASINS FOR W.W.T.S. | N/A | 156 | 16,17 | Two basins built in 1992 are periodically cleaned and visually inspected, typically every two years. No major issues have been identified with the basins themselves - some minor cracking of the concrete in the last inspection two to three years ago. The system has no automated or formal effluent pH control, although it meets site permit requirements. | 4 | (30) | (20+) | 2041 | | | No | No | 1992 |
| 1297 | 9739 | 10038 | 99003531 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | BALANCE OF WASTE WATER TREATMENT | N/A | 157 | 16 | Relatively new and in good condition. | 3a | (20) | 20 | 2041 | | | No | No | 1994 |
| 1297 | 9739 | 7260 | 7405 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT MCC C12 | N/A | 158 | 6 | Relatively new and in good condition. | 3a | (30) | 20+ | 2041 | | | Yes | Yes | 1994 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank

### 11.2.2.4 Actions

Based on the condition assessment, the following actions are recommended for the waste water treatment plant (WWTP):

**TABLE 11-37 RECOMMENDED ACTIONS – WASTE WATER TREATMENT PLANT (WWTP)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | 171 | 16 | Relatively new. No action recommended. | | |
| 1297 | 9739 | 10038 | 7263 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | 172 | 16 | Perform Level 2 thickness measurements of the vessels and visual inspections of the internals. Test lines to oil/water separators and to WWTP basins for flow. | 2011 | 1 |
| 1297 | 9739 | 10038 | 99003527 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | CONCRETE BASINS FOR W.W.T.S. | 173 | 16 | Perform Level 2 concrete base and structural steel. | 2011 | 1 |
| 1297 | 9739 | 10038 | 99003531 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | BALANCE OF WASTE WATER TREATMENT | 174 | 16 | No recommended action. | | |

### 11.2.2.5 Risk Assessment

The risk assessment associated with the waste water treatment plant, both from a technological perspective and a safety perspective, is illustrated below in Table 11-38.

**TABLE 11-38 RISK ASSESSMENT – WASTE WATER TREATMENT PLANT (WWTP)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life | Techno-Eco Risk Assess Model | | | Safety Risk Assess Model | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Comments | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | None | 174 | 28 | See detail below. | | | | | | | | | | |
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | Batch Reactor | 175 | 16 | Minimal corrosion at base and side walls. | 20 | N/A | 1 | A | Low | 1 | B | Low | Tank leak, difficult to access and fix. Station outage if extensive at wrong time. | Inspect, maintain. |
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | Filter Press | 176 | 16 | Failure of press elements. | 25 | N/A | 1 | A | Low | 1 | B | Low | Temporary measures for waste storage. | Inspect, maintain. |
| 1297 | 9739 | 7260 | 7405 | 0 | WATER TREATMENT & ENVIRONMENT | ENVIRONMENTAL MONITORING | WASTE WATER TREATMENT MCC C12 | MCC | 177 | 6 | Not addressed in detail. | 10 | Electrical failure | 2 | A | Low | 2 | A | Low | System shutdown. | Inspect, maintain. |
| 1297 | 9739 | 10038 | 7263 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | Oil Water Separator & Underground Drain Pipes | 178 | 16 | Oil leakage, underground drain leakage. | (10+) | Likely 10+ Years. Inspections are required to assess the remaining life. | 3 | B | Medium | 3 | B | Medium | Leak of drains and possible oil to environment. | Test, maintain. |
| 1297 | 9739 | 10038 | 99003527 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | CONCRETE BASINS FOR W.W.T.S. | Treatment Basins | 179 | 16 | Crack and failure. | (20+) | Likely 20 years. Inspections are required to verify the remaining life. | 1 | C | Low | 1 | B | Low | Basin leak and spill to environment. | Test, maintain. |
| 1297 | 9739 | 10038 | 99003531 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | BALANCE OF WASTE WATER TREATMENT | None | 180 | 16 | | | | | | | | | | | |

### 11.2.2.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Several curves are required to represent the various elements. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment equivalent base loaded operating life limits.

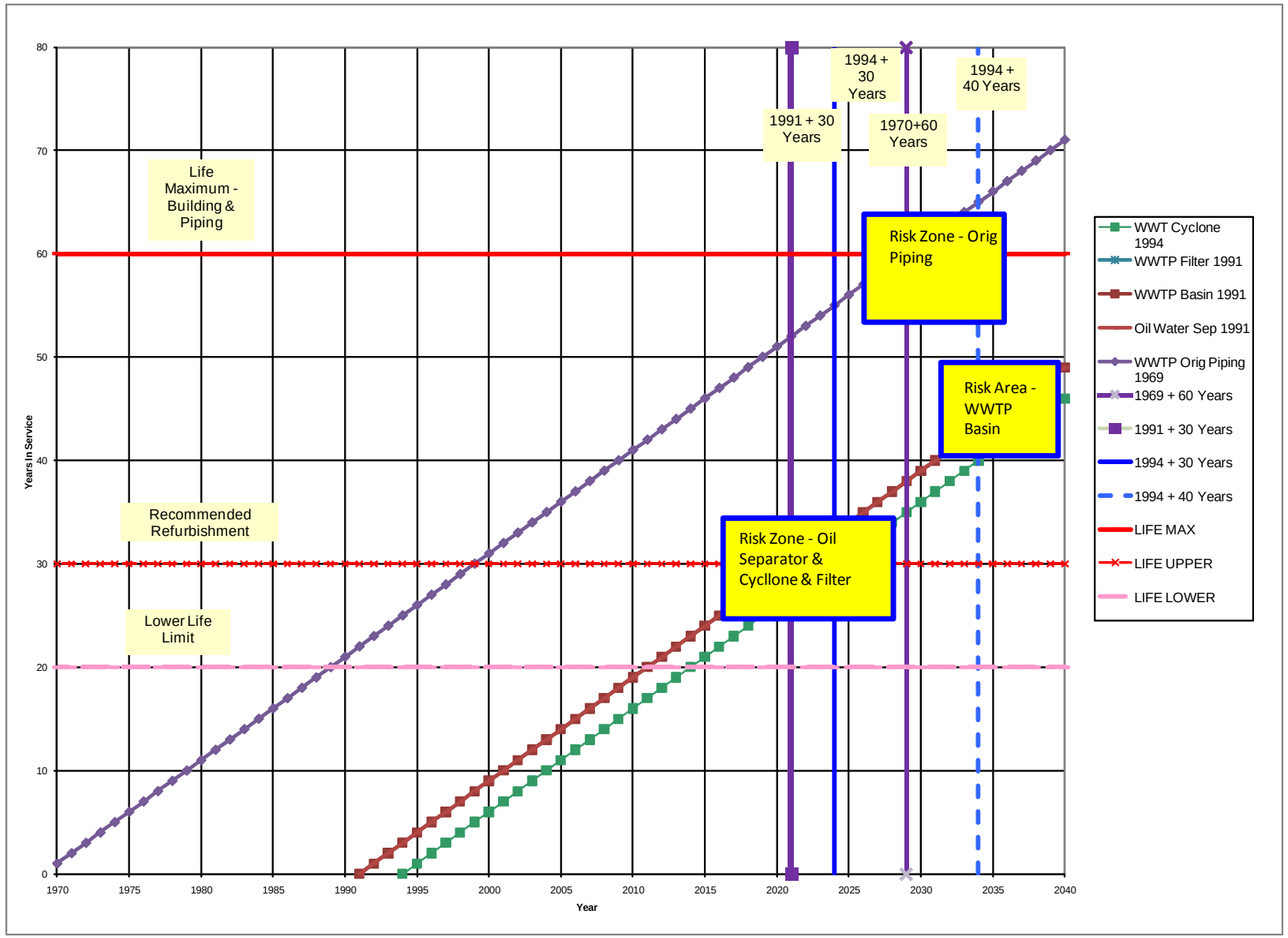



**FIGURE 11-29 LIFE CYCLE CURVE – WASTE WATER TREATMENT PLANT (WWTP)**

The curves indicate that the remaining life (RL) of most of the waste water treatment plant (WWTP) system exceeds the desired life (DL) which is the end date for generation of 2020. The exception is the WWTP basin building which requires refurbishment/replacement. The dates for the oil separation and piping and basin tanks are subject to inspection information required.

### 11.2.2.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-39 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-39 LEVEL 2 INSPECTION – WASTE WATER TREATMENT PLANT (WWTP)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 10038 | 0 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | N/A | 151 | 16 | For Building: See Building-WWTP in Table 11-19. | | | |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | Oil Water Separators | 152 | 16 | Thickness measurement of oil water separators and coating, and visual Inspection of internals. | 2011 | 2 | $75 |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | Oily Water & Discharge Pipes | 153 | 16 | Thickness measurement of underground oily water pipes and other discharge pipes underground. Leak check. | 2011 | 2 | $15 |
| 1297 | 9739 | 10038 | 99003527 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | CONCRETE BASINS FOR W.W.T.S. | N/A | 154 | 16 | Concrete test of basin floor. | 2011 | 3 | $18 |
| 1297 | 9739 | 10038 | 99003531 | WATER TREATMENT AND ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | BALANCE OF WASTE WATER TREATMENT | N/A | 156 | 16 | No Level 2 required. | | | |

### 11.2.2.8 Capital Projects

The suggested typical capital enhancements for the waste water treatment plant include:

**TABLE 11-40 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – WASTE WATER TREATMENT PLANT (WWTP)**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 10038 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | WASTE WATER TREATMENT SYSTEM | 160 | | For Building: See Building-WWTP in Table 11-20. | | |
| 1297 | 9739 | 10038 | 7263 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | OIL/WATER SEPARATORS | 161 | 16 | Refurbish oil water separator. | 2015 | 1 |
| 1297 | 9739 | 10038 | 99003527 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | CONCRETE BASINS FOR W.W.T.S. | 162 | | No capital required. | | |
| 1297 | 9739 | 7260 | 7405 | 0 | WATER TREATMENT & ENVIRONMENT | ENVIRONMENTAL MONITORING | WASTE WATER TREATMENT MCC C12 | 163 | | No capital required. | | |
| 1297 | 9739 | 10038 | 99003531 | 0 | WATER TREATMENT & ENVIRONMENT | WASTE WATER TREATMENT SYSTEM | BALANCE OF WASTE WATER TREATMENT | 164 | | No capital required. | | |

### 11.2.3 Asset 9739 – Water Treatment Plant (WTP) System

(Detailed Technical Assessment in Working Papers, Appendix 2, Condensate Polishing - Appendices 15, 21)

| | |
|---|---|
| Unit #: | Common Facilities |
| Asset Class # | BU 1297 - Assets Common |
| SCI & System: | 9739 HRD Water Treatment & Environment |
| Sub-Systems: | 7203 HRD Water Treatment Plant |
| Components: | 286057 Water Treatment Plant Systems |
| Sub-Components: | 6802 WTP Brine System<br>7185 WTP & MCC C5<br>7212 WTP Sulphuric Acid System<br>7213 WTP Flocculent Chem Inj<br>7214 WTP Primary Train<br>7220 WTP Mixed Bed<br>7410 WT MCC C10<br>7422 WTP Clarifier System<br>8748 WTP & Aux Blr MCC WTP-34<br>9864 WTP Sand Filter<br>9879 WTP Clearwell System<br>9995 6400 Chem Inj<br>10037 WTP Caustic System |

#### 11.2.3.1 Description

The Water Treatment Plant at Holyrood Thermal Generation Station (HTGS) serves Unit 1, Unit 2 and Unit 3. This includes the major equipment elements:

- Clarifier system (1) and auxiliaries;
- Sand filters (3) and auxiliaries;
- Clearwell System (1) and auxiliaries;
- Primary Cation and Anion demineralizer Trains - replaced in 1992;
- Mixed Cation/Anion Bed Trains - replaced in 1992;
- Bulk Acid and Caustic Storage Vessels; and
- Demin Water Storage Vessel – replaced in 1992.

In addition, there are other smaller items such as acid and caustic storage tanks, brine system, chemical injection systems, flocculent chemical injection systems, and pumps.






FIGURE 11-30 WATER TREATMENT PLANT – SAND FILTERS; CLARIFIER ADDITIVE TANKS





FIGURE 11-31 WATER TREATMENT PLANT – CLEARWELL AND DEMINERALIZED WATER TANK



FIGURE 11-32 ACID & CAUSTIC AREA

The fresh water supply for the water treatment plant originates at Quarry Brook dam and moves through a 41 cm (16 inch) underground line to the circulating water pumphouse. It moves from the pumphouse through a 20 cm (8 inch) branch line which terminates at the raw water sump. From the raw water sump the water is pumped to the clarifier.

#### 11.2.3.2 History - Inspection and Repair History

**Water Storage Vessels:** The major storage vessels (clarifier, sand filters, demin storage) are original equipment, installed around 1969. They have generally been reasonably well maintained and checked for process integrity.

The clarifier has received minimum inspections and written record was not available. Visual inspections are said to occur on a 5 year frequency. There is no record of thickness testing or NDT examination of the clarifier. Several sub-systems (impellors, mixer motors, etc.) have been replaced or improved over the years as a part of a regular maintenance program. The impeller shaft steady bearing and sample lines have recently been replaced. In some cases, various internal and external patching has been undertaken on an as-required basis.

In 2009, one sand filter vessel had an ultrasonic thickness assessment done which showed some metal losses at the base. Visually the tank walls are in good shape for their age. However, some localized repairs have been made to the coating on the vessel walls and there is some corrosion at vessel base.

No major structural inspections seem to have been undertaken recently and there is external evidence of corrosion at the base of some of the carbon steel vessels.

**Bulk Acid & Bulk Caustic Storage Tanks:** The bulk acid and bulk caustic storage tanks are only about 13 years old. They have been reasonably well maintained and checked for process integrity. Several sub-systems (pumps, motors, etc.) have been replaced or improved over the years as a part of a regular maintenance program. There have been no regular inspections on these tanks, although there may have been some thickness testing performed, but no records were found. It is known that some of the piping

external to the tanks is plugged and, based on interviews with plant staff, there may be as much as 30 cm of sludge in the bottom of these tanks.

**Major Process Systems & Vessels:** The major process systems and their associated vessels (primarily the anion, cation and mixed bed systems) were upgraded in 1992, after the original systems were in-service for approximately 22 years (approximately 80,000 hours of operation). They are reported to be in excellent shape and performing well. No regular inspections on these vessels were identified, although their performance is continuously recorded and examined for significant changes.

### 11.2.3.3 Condition Assessment

The condition assessment of the water treatment plant system is illustrated below in Table 11-41.

**TABLE 11-41 CONDITION ASSESSMENT – WATER TREATMENT PLANT (WTP) SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT | N/A | 117 | 28 | Upgraded in 1992 to address water quality issues. | 4 | 200000 (30) | 20 | 2041 | | | Yes | No | 1968/1992/ 1997 |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | N/A | 118 | 15 | Largely 16" asbestos concrete pipe, installed in 1969. Two sections replaced: 105 m in the warehouse yard replaced with 400 mm PVC pipe in 1996, and 80 m near Pumphouse #2 with 18" Sclair pipe in 1976. No documentation of a recent inspection of the piping appears to exist, although generic data suggests that it should be in good condition. | 4 | (50+) | (20) | 2041 | | | No | No | 1968 |
| 1297 | 9739 | 7203 | 7210 | 7534 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY | N/A | 119 | 15 | Surface inspection in March 2009 indicated the structure was in good shape. No diving inspection has been carried out since 2007 so subsurface condition is uncertain.. | 4 | (30) | (20) | 2041 | | | No | No | 1968-1990 |
| 1297 | 9739 | 7203 | 7210 | 8937 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP SOUTH | N/A | 120 | 15 | Good with continued maintenance and replace as required. | 3a | (40) | 10 | 2041 | | | No | No | |
| 1297 | 9739 | 7203 | 7210 | 8975 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP NORTH | N/A | 121 | 15 | Good with continued maintenance and replace as required. | 3a | (40) | 10 | 2041 | | | No | No | |
| 1297 | 9739 | 7203 | 7211 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | N/A | 122 | 15 | Domestic Water Treatment Plant is in reasonable shape, but likely to required ongoing maintenance and repairs. The polyethylene pipe used for distribution is generally good for approximately 50 years. No issues have been identified other than the quality (i.e. non-drinking water quality). | 3a | (40) | 5+ | 2041 | | | No | No | 1968-1990 |
| 1297 | 9739 | 7203 | 9857 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | GENERAL SERVICE COOLING WATER | N/A | 123 | 12 | Good with continued maintenance and replace as required. | 4 | (30) | 10 | 2041 | | | No | No | 1968-1990 |
| 1297 | 9739 | 7203 | 286053 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHERS | N/A | 124 | 21 | See details below. | | | | | | | | | |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | N/A | 125 | 21 | No known inspections or information. Likely internals and lining issues. | 4 | (25) | 5+ | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | acid and caustic storage tanks | 126 | 21 | Relatively new and likely in good shape, but should be cleaned, No recent inspection. Transfer pumps old and likely needing replacement. | 4 | (25) | (10) | 2020 | | | No | No | 1995 |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | operating panels | 127 | 21 | Panel in poor shape and near obsolescence end of life, alarm panel as well. | 4 | (25) | (2+) | 2020 | | | No | No | 1995 |
| 1297 | 9739 | 7203 | 286053 | 7401 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC A1-3 | N/A | 128 | 6 | Not reviewed. Aging equipment likely obsolete. | 4 | (25) | (5) | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | N/A | 129 | 21 | No known inspections or information. Likely some internals and lining issues. | 4 | (25) | (5+) | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | acid and caustic storage tanks | 130 | 21 | No recent inspection. Likely in good shape, but should be cleaned. Transfer pumps likely need replacement. | 4 | (20) | (10) | 2020 | | | No | No | 1995 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | operating panels | 131 | 21 | Panel in poor shape and likely near obsolescence end of life, alarm panel as well. | 4 | (20) | (2+) | 2020 | | | No | No | 1995 |
| 1297 | 9739 | 7203 | 286053 | 8171 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC B1-3 | N/A | 134 | 6 | Not reviewed. Aging equipment likely obsolete. | 4 | (25) | 5 | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | N/A | 135 | 21 | No known inspections or information. Likely internals and lining issues. | 4 | (25) | 5 | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | acid and caustic storage tanks | 136 | 21 | Likely in good shape, but should be cleaned, No recent inspection. Transfer pumps likely need replacement. | 4 | (20) | (10) | 2020 | | | No | no | 1995 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | operating panels | 137 | 21 | Panel in poor shape and likely near obsolescence end of life. Alarm panel replaced in 2009. | 4 | (20) | (2+) | 2020 | | | No | No | 1995 |
| 1297 | 9739 | 7203 | 286053 | 8727 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER BAB 3-3 | N/A | 138 | 6 | Not reviewed. Aging equipment likely obsolete. | 4 | (25) | (5) | 2020 | | | No | No | 1979 |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | N/A | 139 | 28 | | 4 | (30) | 20 | 2020 | | | Yes | Yes | 1979 |
| 1297 | 9739 | 7203 | 286057 | 6802 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. BRINE SYSTEM | N/A | 140 | 28 | Upgraded in 1992 to address water quality issues. | 3a | (30) | 15 | 2020 | | | Yes | Yes | 1992 |
| 1297 | 9739 | 7203 | 286057 | 7185 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREAT & MCC C5 | N/A | 141 | 6 | Relatively new. Upgraded during WTP upgrade. | 3a | (30) | (15+) | 2020 | | | No | No | 1968/1992 |
| 1297 | 9739 | 7203 | 286057 | 7212 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | N/A | 142 | 28 | Installed in 1997.Several sub-systems (pumps, motors, etc.) replaced or improved. Acid and caustic lines into the plant replaced. | 3a | (30) | (15+) | 2020 | | | No | No | 1997 |
| 1297 | 9739 | 7203 | 286057 | 7213 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WTP FLOCULANT CHEMICAL INJECT. | N/A | 143 | 28 | Upgraded in 1992 to address water quality issues. | 3a | (40) | 15 | 2020 | | | Yes | Yes | 1992 |
| 1297 | 9739 | 7203 | 286057 | 7214 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. PRIMARY TRAINS | N/A | 144 | 28 | Upgraded in 1992 to address water quality issues. | 3a | (40) | 15+ | 2020 | | | Yes | Yes | 1992 |
| 1297 | 9739 | 7203 | 286057 | 7220 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. MIXED BEDS | N/A | 145 | 28 | Upgraded in 1992 to address water quality issues. | 3a | (30) | 15+ | 2020 | | | Yes | Yes | 1992 |
| 1297 | 9739 | 7203 | 286057 | 7410 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT MCC C10 | N/A | 146 | 28 | Upgraded in 1992 to address water quality issues. | 3a | (40) | 15 | 2020 | | | Yes | Yes | 1992 |

Table 11-41 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286057 | 7422 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLARIFIER SYSTEM | N/A | 147 | 28 | Installed in 1969. Reasonably well maintained. Several sub-systems (impellors, mixer motors, etc.) replaced or improved. Some internal and external patching applied. No thickness testing or other major structural inspections recently. Some external corrosion at the tank base. |
| 1297 | 9739 | 7203 | 286057 | 8748 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W T P & AUX. BLR MCC WTP-34 | N/A | 148 | 6 | Relatively new during upgrade. |
| 1297 | 9739 | 7203 | 286057 | 9864 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SAND FILTER SYSTEM | N/A | 149 | 28 | Installed in 1969. Well maintained, but some external evidence of corrosion at vessel base. 2009 thickness measurements near the tank bottoms. |
| 1297 | 9739 | 7203 | 286057 | 9879 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLEARWELL SYSTEM | N/A | 150 | 28 | Installed in 1969. Well maintained as a part of a regular maintenance program. |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The "Next Regular Inspection" column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The "Next Planned Overhaul or Major Inspection" column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a "Desired Life" stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for "Next Regular Inspection" or "Next Planned Overhaul/Major Inspection", they are left blank.

### 11.2.3.4 Actions

Based on the condition assessment, the following actions are recommended for the water treatment plant system:

**TABLE 11-42 RECOMMENDED ACTIONS – WATER TREATMENT PLANT (WTP) SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 0 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT & ENVIRONMENT | 126 | 28 | Improve ventilation and paint roofing. | 2012 | 1 |
| 1297 | 9739 | 7203 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT | 127 | 28 | Refurbish roofing. | 2015 | 1 |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | 128 | 15 | Perform Level 2 inspections. | 2011 | 1 |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | 129 | 15 | Develop a program of ongoing inspections and performance testing based on industry best practices. | 2011 | 1 |
| 1297 | 9739 | 7203 | 7210 | 7534 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | 130 | 15 | Perform Level 2 inspections. | 2011 | 1 |
| 1297 | 9739 | 7203 | 7210 | 8937 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP SOUTH | 131 | 15 | No recommended action. | | |
| 1297 | 9739 | 7203 | 7210 | 8975 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP NORTH | 132 | 15 | No recommended action. | | |
| 1297 | 9739 | 7203 | 7211 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | 133 | 15 | Perform Level 2 inspections. | 2011 | 2 |
| 1297 | 9739 | 7203 | 7211 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | 134 | 15 | Develop a program of ongoing inspections and performance testing based on industry best practices. | 2011 | 2 |
| 1297 | 9739 | 7203 | 9857 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | GENERAL SERVICE COOLING WATER | 135 | 12 | Maintain and refurbish. | 2012 | 2 |
| 1297 | 9739 | 7203 | 286053 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHERS | 136 | 21 | See details below. | | |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 137 | 21 | Perform Level 2 inspections on polisher process vessels. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 138 | 21 | Clean and inspect acid and caustic storage tanks at next resin change-out. | 2011 | 1 |

Table 11-42 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 139 | 21 | Replace Units 1 and 2 annunciator panels. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 140 | 21 | Assess the replacement of operating panels and acid/caustic piping. | 2012 | 1 |
| 1297 | 9739 | 7203 | 286053 | 7401 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC A1-3 | 141 | 6 | Refurbish or replace. | 2012 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 144 | 21 | Perform Level 2 inspections on polisher process vessels. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 145 | 21 | Clean and inspect acid and caustic storage tanks at next resin change-out. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 146 | 21 | Replace Units 1 and 2 annunciator panels. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 147 | 21 | Assess the replacement of operating panels and acid/caustic piping. | 2012 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8171 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC B1-3 | 148 | 6 | Refurbish or replace. | 2012 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER PLANT | 149 | 21 | Perform Level 2 inspections on polisher process vessels. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER PLANT | 150 | 21 | Clean and inspect acid and caustic storage tanks at next resin change-out. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER PLANT | 151 | 21 | Assess the replacement of operating panels and acid/caustic piping. | 2012 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER PLANT | 152 | 21 | See detail below. | | |
| 1297 | 9739 | 7203 | 286053 | 8727 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER BAB 3-3 | 153 | 6 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | 154 | | See details below | | |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | 155 | 34 | Identify Level 2 activities to investigate potential damage mechanisms from lay-up. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | 156 | 34 | Review lay-up practices re: industry guidelines. Use Level 2 results to define relative risk of not complying with industry guidelines. | 2013 | 1 |

Table 11-42 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286057 | 6802 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. BRINE SYSTEM | 157 | 28 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7185 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREAT & MCC C5 | 158 | 6 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7212 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | 159 | 28 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7213 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WTP FLOCCULANT CHEMICAL INJECT. | 160 | 28 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7214 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. PRIMARY TRAINS | 161 | 28 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7220 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. MIXED BEDS | 162 | 28 | No recommended action. | | |
| 1297 | 9739 | 7203 | 286057 | 7410 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT MCC C10 | 163 | 6 | Relatively new. Not examined in detail. | | |
| 1297 | 9739 | 7203 | 286057 | 7422 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLARIFIER SYSTEM | 164 | 28 | Perform Level 2 thickness measurements of the clarifier vessel and visual inspections of the internals. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286057 | 8748 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W T P & AUX. BLR MCC WTP-34 | 165 | 6 | Relatively new. Not examined in detail. No action advised. | | |
| 1297 | 9739 | 7203 | 286057 | 9864 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SAND FILTER SYSTEM | 166 | 28 | Perform Level 2 thickness measurements of the clarifier vessel and visual inspections of the internals. | 2011 | 1 |
| 1297 | 9739 | 7203 | 286057 | 9879 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLEARWELL SYSTEM | 167 | 28 | No recommended action. | | |

### 11.2.3.5 Risk Assessment

The risk assessment associated with the water treatment plant, both from a technological perspective and a safety perspective, is illustrated below in Table 11-43.

**TABLE 11-43 RISK ASSESSMENT – WATER TREATMENT PLANT (WTP) SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life | Techno-Eco Risk Assess Model | | | Safety Risk Assess Model | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Comments | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 9739 | 0 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT & ENVIRONMENT | None | 140 | 15 | See details below. | | N/A | | | | | | | | |
| 1297 | 9739 | 7203 | 0 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT | None | 141 | 15 | See details below. | | N/A | | | | | | | | |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Raw Fresh Water Supply Pipe | 142 | 15 | Mechanical fatigue. | (20) | N/A | 2 | C | Medium | 2 | C | Medium | Loss of fresh water for services – unit shutdowns for repairs. | Inspect, maintain and replicate. |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Fire Supply Mains | 143 | 15 | SCC, FAC, thermal/ mechanical fatigue, corrosion-fatigue. | (20) | N/A | 1 | C | Low | 2 | C | Medium | Inability to operate safely – unit shutdowns until repaired. | Inspect and maintain. |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Fire Supply Sub-Systems | 144 | 15 | SCC, FAC, thermal/ mechanical fatigue, corrosion-fatigue. | (20) | N/A | 1 | B | Low | 2 | B | Medium | Inability to operate safely – unit shutdowns until repaired or temporary measures in place. | Inspect and maintain. |
| 1297 | 9739 | 7203 | 7210 | 7534 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | Quarry Brook Dam | 145 | 15 | Mechanical aging. | (20) | N/A | 2 | C | Medium | 2 | C | Medium | Dam leak/failure – loss of fresh water for all services – unit shutdowns for repairs. | Inspect and maintain. |
| 1297 | 9739 | 7203 | 7210 | 8937 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP SOUTH | None | 146 | 15 | Mechanical/electrical failure. | 5+ | N/A | 1 | B | Low | 1 | B | Low | Reliability of 2nd pump re ability to operate safely. | Spare, maintain. |
| 1297 | 9739 | 7203 | 7210 | 8975 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP NORTH | None | 147 | 15 | Mechanical/electrical failure. | 5+ | N/A | 1 | B | Low | 1 | B | Low | Reliability of 2nd pump re ability to operate safely. | Spare, maintain. |
| 1297 | 9739 | 7203 | 7211 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | Domestic Water Supply | 148 | 15 | Mechanical/electrical failure. | 5+ | N/A | 2 | A | Low | 2 | A | Low | Loss of domestic water services – minimal impact. | Inspect and maintain. |
| 1297 | 9739 | 7203 | 9857 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | GENERAL SERVICE COOLING WATER | None | 149 | 12 | Mechanical/corrosion. | (5+) | N/A | 3 | A | Low | 3 | a | Low | Loss of GSW Cooling | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286053 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHERS | None | 150 | 21 | See details below. | | N/A | | | | | | | | |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | Polisher Vessels | 151 | 21 | Corrosion. | (5+) | Spark Test and internals inspections are required to assess the remaining life. | 2 | B | Low | 2 | A | Low | Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit. | Test, maintain. |
| 1297 | 9739 | 7203 | 286053 | 7401 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC A1-3 | None | 152 | 6 | Electrical failure. | (5) | N/A | 2 | B | Low | 2 | A | Low | Loss of polished condensate | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | Polisher Vessels | 155 | 21 | Corrosion. | (5+) | Spark Test and internals inspections are required to assess the remaining life. | 2 | B | Low | 2 | A | Low | Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit. | Test, maintain. |
| 1297 | 9739 | 7203 | 286053 | 8171 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC B1-3 | None | 156 | 6 | Electrical failure. | (5) | N/A | 2 | B | Low | 2 | A | Low | Loss of polished condensate | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER PLANT | Polisher Vessels | 157 | 21 | Corrosion. | (5+) | Spark Test and internals inspections are required to assess the remaining life. | 2 | B | Low | 2 | A | Low | Rubber liner and shell failure/leak requires patch and subsequent short shutdown of unit. | Test, maintain. |
| 1297 | 9739 | 7203 | 286053 | 8727 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER BAB 3-3 | None | 158 | 6 | Electrical failure. | (5) | N/A | 2 | B | Low | 2 | A | Low | Loss of polished condensate | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Demin Water Tank | 159 | 28 | Demin water corrosion. | 15+ | 2020 OK | 1 | B | Low | 2 | A | Low | Tank leak, difficult to access and fix. Station outage if extensive. | Maintain. |
| 1297 | 9739 | 7203 | 286057 | 6802 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. BRINE SYSTEM | None | 160 | 17 | Not addressed. | 15 | N/A | 1 | B | Low | 1 | B | Low | Water quality drop. Rely on storage until fix. | Inspect, clean, maintain. |
| 1297 | 9739 | 7203 | 286057 | 7185 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREAT & MCC C5 | None | 161 | 6 | Electrical failure. | 15+ | 2 | 2 | B | Low | 2 | A | Low | Storage until fixed. | Inspect and maintain. |
| 1297 | 9739 | 7203 | 286057 | 7212 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | Acid & Caustic Storage Tanks | 162 | 28 | Acid and Caustic Corrosion;; | (15+) | Inspections are required to assess the remaining life. | 1 | B | Low | 1 | B | Low | Tank leak, difficult to access and fix. Station outage if extensive. | Inspect, clean, maintain. |
| 1297 | 9739 | 7203 | 286057 | 7213 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WTP FLOCCULANT CHEMICAL INJECT. | None | 163 | 28 | Not addressed | 15 | N/A | 1 | B | Low | 1 | B | Low | Tank leak, difficult to access and fix. Station outage if extensive. | Inspect, clean, maintain. |

Table 11-43 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | Remaining Life Comments | Techno-Eco Risk Assess Model Likeli-hood | Techno-Eco Risk Assess Model Conse-quence | Techno-Eco Risk Assess Model Risk Level | Safety Risk Assess Model Likeli-hood | Safety Risk Assess Model Conse-quence | Safety Risk Assess Model Safety Risk | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286057 | 7214 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. PRIMARY TRAINS | None | 164 | 28 | Mechanical, process failure. | 15+ | N/A | 2 | B | Low | 2 | C | Medium | Loss of demineralized water supply | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286057 | 7220 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. MIXED BEDS | Anion/Cation/Mixed Bed Demineralizers | 165 | 28 | Demin water, acid and caustic corrosion. | 15+ | Life to 2020+ very likely | 1 | B | Low | 1 | B | Low | Tank leak. Redundancy limits impact. | Inspect, clean, maintain. |
| 1297 | 9739 | 7203 | 286057 | 7410 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT MCC C10 | None | 166 | 6 | Electrical failure. | 15+ | | 2 | B | Low | 2 | A | Low | Short WYTP shutdown. Storage until fixed. | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286057 | 7422 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLARIFIER SYSTEM | Clarifier | 167 | 28 | Corrosion at base and side walls. | (10+) | Ultrasonic thickness and visual internal inspections are required to assess the remaining life. | 3 | C | Medium | 3 | A | Low | Tank leak, difficult to access and fix. Station outage if extensive. | Test, maintain. |
| 1297 | 9739 | 7203 | 286057 | 8748 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W T P & AUX. BLR MCC WTP-34 | | 168 | 6 | Electric Failure | 10 | N/A | 2 | B | Low | 2 | A | Low | Short WYTP shutdown. Storage until fixed. | Inspect, maintain. |
| 1297 | 9739 | 7203 | 286057 | 9864 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SAND FILTER SYSTEM | Sand Filters | 169 | 28 | Corrosion at base and side walls. | (10+) | Likely Ok to 2020. Visual internal inspections are required to assess the remaining life. | 2 | A | Low | 2 | A | Low | Tank Leak. Redundancy limits impact. | Test, maintain. |
| 1297 | 9739 | 7203 | 286057 | 9879 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLEARWELL SYSTEM | Clearwell | 170 | 28 | Corrosion at base and side walls. | (10+) | Ultrasonic thickness and visual internal inspections are required to assess the remaining life. | 2 | B | Low | 2 | A | Low | Tank leak, difficult to access and fix. Station outage if extensive. | Inspect, maintain. |

### 11.2.3.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are illustrated to represent the original equipment (clarifiers, sand filters, clearwell) and the new systems (demineralizers, demin storage, acid and caustic systems). The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. Although linked to water production levels and hence to steam generation operation, it was felt that the best indicator was physical aging. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years.

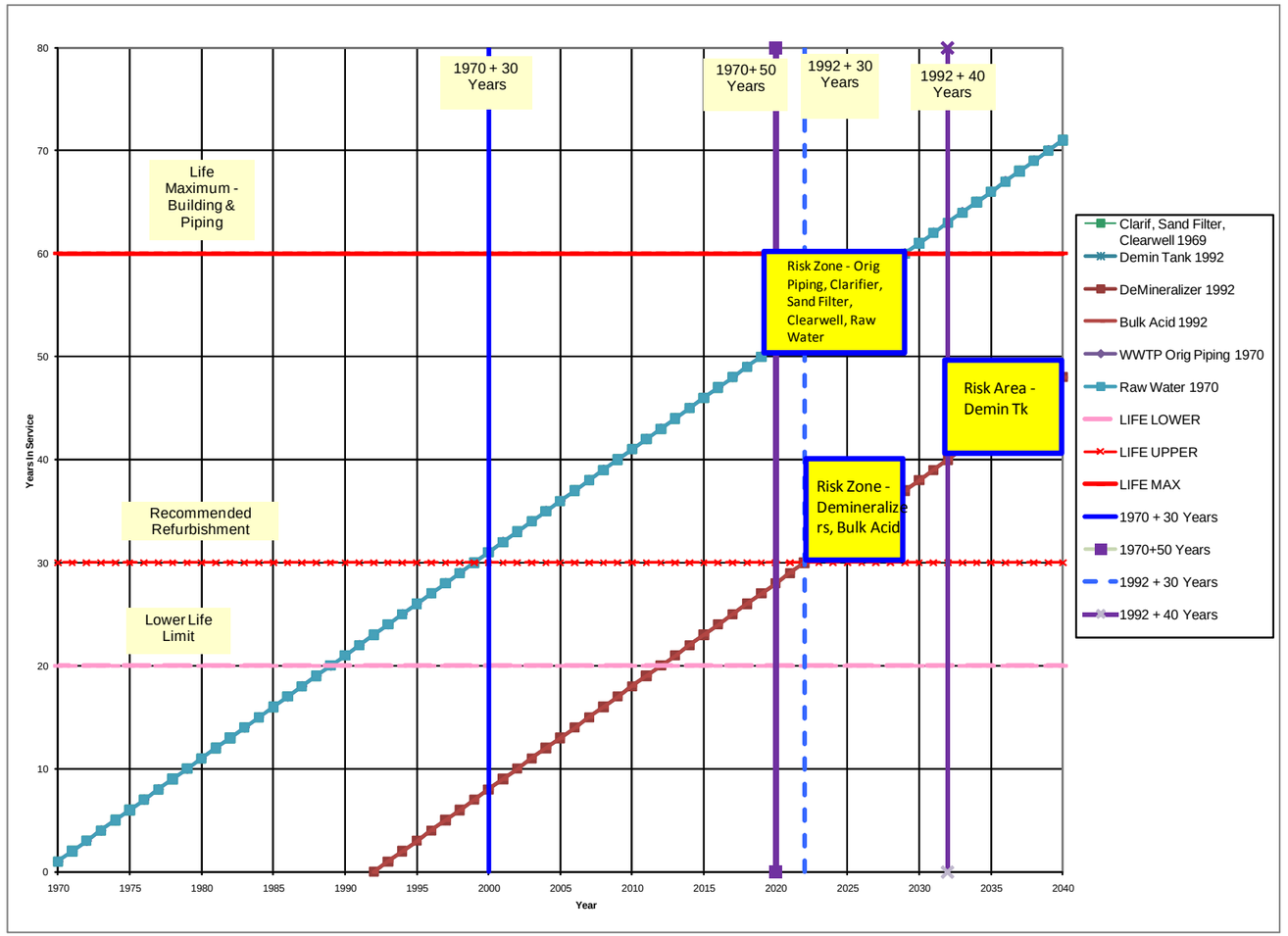



**FIGURE 11-33 LIFE CYCLE CURVE – WATER TREATMENT PLANT (WTP) SYSTEM**

The curves indicate that the remaining life (RL) of the water treatment plant (WTP) system exceeds the desired life (DL) which is the end date for generation of 2020. This is dependent on the condition primarily of the original equipment. Given they represent a single contingency failure mode, an assessment of their condition is critical to firming this assessment. Similarly, their importance as a single contingency failure mode makes an understanding of the condition of the raw water line from the storage pond and the dam at the storage pond a critical task.

### 11.2.3.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-44 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-44 LEVEL 2 INSPECTION – WATER TREATMENT PLANT (WTP) SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 0 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT | | 117 | 28 | No Level 2 | | | |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Pipeline | 118 | 15 | NDE pipeline from Quarry Brook Dam to pumphouse – in-pipe crawler or other device to check for thickness and/or leaks. | 2011 | 1 | $37 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | Dam | 119 | 15 | Visual inspection of dam underwater – diver investigate visually for any unusual signs of deterioration. | 2011 | 1 | $22 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP SOUTH | N/A | 120 | 15 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP NORTH | N/A | 121 | 15 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 7211 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | N/A | 122 | 15 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 9857 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | GENERAL SERVICE COOLING WATER | N/A | 123 | 15 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHERS | N/A | 124 | 15 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | N/A | 125 | 21 | Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels. | 2011 | 1 | $30 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC A1-3 | N/A | 126 | 6 | No Level 2 required. | 0 | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | N/A | 127 | 21 | Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels. | 2011 | 1 | $30 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC B1-3 | N/A | 130 | 6 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | N/A | 131 | 21 | Visual inspection of polisher vessel internals; spark test rubber liner; NDE polisher vessel representative thickness; clean and inspect acid and caustic vessels. | 2011 | 1 | $30 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER BAB 3-3 | N/A | 132 | 6 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Clarifier, Sand Filters, Clearwell | 133 | 28 | Inspections of clarifier, sand filters, clearwell internals. | 2011 | 1 | $75 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Water Chemistry | 134 | 34 | Identify Level 2 condition assessment activities to investigate the potential damage mechanisms resulting from lay-up. | 2012 | 2 | (Incl in Unit 1 Blr) |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Water Chemistry | 135 | 34 | Review lay-up practices relative to industry guidelines. Results of Level 2 inspections will assist in defining the relative risk of not complying with industry guidelines. | 2012 | 2 | (Incl in Unit 1 Blr) |

Table 11-44 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Water Chemistry | 136 | 34 | Review cycle water treatment to 2020, including: operating data to assess the actual operating targets and compliance; physical assets including sample points, analyzers, and chemical injection; equipment inspection results to corroborate effects and risks with the current chemistry treatment regime, and identification of potential changes to the present cycle chemistry treatment regime, and the benefits of those changes relative to the operating objectives. | 2012 | 2 | (Incl in Unit 1 Blr) |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. BRINE SYSTEM | N/A | 137 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREAT & MCC C5 | N/A | 138 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | Acid & Caustic Tanks | 139 | 28 | Inspect internals and NDE thickness of acid and caustic tanks. | 2011 | 2 | $15 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WTP FLOCULANT CHEMICAL INJECT. | N/A | 140 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. PRIMARY TRAINS | N/A | 141 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. MIXED BEDS | N/A | 142 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT MCC C10 | N/A | 143 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLARIFIER SYSTEM | Clarifier | 144 | 28 | Ultrasonic NDE thickness of clarifier walls. | 2011 | 2 | (Incl in 133) |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W T P & AUX. BLR MCC WTP-34 | N/A | 145 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SAND FILTER SYSTEM | N/A | 146 | 28 | No Level 2 required. | | | |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLEARWELL SYSTEM | N/A | 147 | 28 | No Level 2 required. | | | |

### 11.2.3.8 Capital Projects

The suggested typical capital enhancements for the water treatment plant include:

**TABLE 11-45 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – WATER TREATMENT PLANT (WTP) SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 0 | 0 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT &ENVIRONMENT | 125 | | No capital required. | | |
| 1297 | 9739 | 7203 | 0 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT | 126 | 28 | None; connect to DCS (PLC obsolescence). | 2011 | 1 |
| 1297 | 9739 | 7203 | 7210 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER SYSTEM | 127 | 15 | Implement new or parallel fresh water line from Quarry Brook Dam. | 2013 | 1 |
| 1297 | 9739 | 7203 | 7210 | 7534 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | 128 | | No capital required. | | |
| 1297 | 9739 | 7203 | 7210 | 8937 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP SOUTH | 129 | | No capital required. | | |
| 1297 | 9739 | 7203 | 7210 | 8975 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | RAW WATER PUMP NORTH | 130 | | No capital required. | | |
| 1297 | 9739 | 7203 | 7211 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | DOMESTIC WATER SYSTEM | 131 | | No capital required. | | |
| 1297 | 9739 | 7203 | 9857 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | GENERAL SERVICE COOLING WATER | 132 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286053 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHERS | 133 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 134 | 21 | Replace alarm annunciation panels | 2011 | 2 |
| 1297 | 9739 | 7203 | 286053 | 6967 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | 135 | 21 | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 2 |
| 1297 | 9739 | 7203 | 286053 | 7401 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC A1-3 | 136 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 137 | 21 | Replace alarm annunciation panels. | 2011 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8127 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | 138 | 21 | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8171 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER MCC B1-3 | 141 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | 142 | 21 | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 1 |
| 1297 | 9739 | 7203 | 286053 | 8686 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | 143 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286053 | 8727 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | CONDENSATE POLISHER BAB 3-3 | 144 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 0 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | 145 | 34 | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 6802 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. BRINE SYSTEM | 146 | | No capital required. | | |

Table 11-45 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 9739 | 7203 | 286057 | 7185 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREAT & MCC C5 | 147 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7212 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | 148 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7213 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WTP FLOCCULANT CHEMICAL INJECT. | 149 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7214 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. PRIMARY TRAINS | 150 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7220 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. MIXED BEDS | 151 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7410 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | WATER TREATMENT MCC C10 | 152 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 7422 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLARIFIER SYSTEM | 153 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 8748 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W T P & AUX. BLR MCC WTP-34 | 154 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 9864 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. SAND FILTER SYSTEM | 155 | | No capital required. | | |
| 1297 | 9739 | 7203 | 286057 | 9879 | WATER TREATMENT AND ENVIRONMENT | WATER TREATMENT PLANT | W.T.P. CLEARWELL SYSTEM | 156 | | No capital required. | | |

### 11.2.4 Asset 7133 – Marine Terminal

The marine terminal and facilities was excluded from the assessment at the kick-off meeting and are being looked at by others.

### 11.2.5 Asset 7202 – Gas Turbine Genset

(Detailed Technical Assessment in Working Papers, Appendix 13)

| | |
|---|---|
| Unit #: | GAS TURBINE |
| Asset Class # | BU 1273 Gas Turbine |
| SCI & System: | 7202 Gas Turbine System |
| Sub-Systems: | 7058 GT Power Turb & G/B<br>7308 GT Avon Jet Engine<br>7309 GT Gen<br>7310 HRD GT E&C<br>7311 GT Aux Systems |

#### 11.2.5.1 Description

| | |
|---|---|
| Original Manufactured/Delivered | 1969 |
| In-Service Date at Holyrood | 1986 |
| End of Planned Life Date | 2041 |
| Last Combustion System Inspection/Overhaul | 2009 |
| Next Major Overhaul/Inspection | 2011 (Recommended) |
| Next Major Overhaul/Inspection (Planned) | 2011 (On Hold) |
| Planned air intake Upgrade | 2011 (On Hold) |
| Planned new exhaust stack | 2011 (On Hold) |
| Planned air radiator replacement | 2012 (On Hold) |
| Planned air intake & building upgrade | 2014 (On Hold) |
| Planned Upgrades | 2015/16 (On Hold) |

The hours associated with the unit are:

Hours Actual - Ops to Dec 2009

- 1978 – 1,749 operating hrs since new (+85,000 idle hours)
- 1985 – 2,139 operating hrs since new (+170,000 idle hours)
- 1995 – 3,475 operating hrs since new (+256,000 idle hours)
- 2005 – 3,807 operating hrs since new (+343,000 idle hours)
- 2010 – 4,717 operating hrs since new (+386,000 idle hours)

Starts Actual – to Dec 2009

- 1978 – 611 starts, since new
- 1985 – 796 starts
- 1995 – 1,440 starts
- 2005 – 2,025 starts
- 2010 – 2,548 starts (likely between 2,300 and 2,548)

Max Hrs Gen - Ops to End Date 2020 and 2041 (Assuming 4,717 hours in 2010)

- Combustor: 1,400 to 2,800 operating hours to 2023; 3,100 to 6,200 hours to 2041
- PT Volute: 2,900 to 5,300 operating hours to 2023; 4,600 to 7,700 hours to 2041
- Balance: 6,000 to 7,400 operating hours to 2023; 7,700 to 10,800 hours to 2041

Max Starts – Ops to End Date 2020 (assuming 2,548 starts since new as of 2010)

- Combustor: 1,300 starts to 2020; 2,000 starts to 2041
- PT Volute: 2,100 starts to 2020; 2,800 starts to 2041
- Balance: 2,900 starts to 2020; 3,600 starts to 2041

One interesting aspect for early Avon units without corrosion protection was that each standby hour may have consumed the equivalent of 0.3 hours of running life. (Maintenance and Support of Mature Gas Turbines – M. Hudson, Siemens 2005)

The gas turbine generator system at the plant serves as a black start unit for the station. It is occasionally used for system support as well.

**Gas Generator:** The gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine used by Associated Electrical Industries (AEI) of Manchester, England as the power source for the 13.5 MW packaged generating unit. Manufacture of this type generating unit began in the mid 1960's. The unit supplied to the Newfoundland and Labrador Power Commission in 1966 was the first one off the drawing board and was considered to be a development model. The generator unit itself is comprised of a number of components: inlet plenum, AVON 1533-70L, power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system. The three stage turbine in the aft end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rpm and boost delivery. The high temperature, high velocity gas exits the jet through an exhaust transition duct which is used to drive the Power Turbine and thus the generator through a gearbox.

**Inlet Plenum:** The inlet plenum is designed to provide approximately 140,000 cubic feet per minute of combustion air to the jet intake. This plenum is constructed of structural steel plate and framing supported by a concrete foundation. To reduce compressor damage and blade fouling, the inlet air must be free of dust and dirt. Filtration is accomplished by 72 high efficiency "Farr" filter assemblies supported on tubular columns above the intake. The inlet silencer consists of acoustical splitters in a steel shell that is designed with round leading edges to create a bell-mouth entry. The trailing edges are tapered to ensure a low pressure drop and uniform flow characteristics. The plenum chamber is built from 10 cm (4 inch) thick noise-shield panels, packed with acoustic fill and secured to a rigid steel frame.

**Power Turbine:** The power turbine is an Associated Electric Industries Ltd. (AEI) design, manufactured in Manchester, England in early 1966. The power turbine is a single stage overhung machine designed for a normal operational speed of approximately 4900 rpm. The power turbine is connected to the generator via a gearbox with a ratio of 4:1. The power turbine and gearbox are mounted on the centre section of

the unit bedplate with this section also forming the main lubricating oil tank. Auxiliary and emergency oil pumps are mounted on this same base plate.

The power turbine casings (Volute) were replaced in 1986 as part of the major upgrade.

**Exhaust System:** The exhaust casing (volute) is a welded fabrication divided along the horizontal centreline. It turns the gasses transversely to the machine and vertically upwards to the exhaust silencer.

The exhaust stack is constructed of heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stack is constructed of heavy gauge steel plate. This stack was replaced during the 1986 major upgrade. The snow doors on the exhaust stacks are pneumatically actuated and were a new addition in 1986 to reduce corrosion of the volute and power turbine from infiltration of snow and rain water which promoted corrosion within the unit. New limit switches installed on the doors in 2009 indicate the position (opened or closed) of each door at the control station.

**Gear Box:** The main gearbox was manufactured by AEI in Manchester, England. It is designed to provide an approximate 4:1 speed ratio from the power turbine shaft to the main generator shaft. The gear train is fitted to the power turbine rotor by semi-flexible coupling housed within the gearbox. The gears are of the single helical, single reduction type with the pinion mounted directly above the wheel. A removable top cover allows for inspection without disturbing the alignments.

**Generator:** The Generator is an air-cooled, 14MW, 13.8 kV, 3 phase, Type AG 80/100, built by Associated Electric Industries (AEI) of Rugby, England in 1966. It has a rotating-field, salient-pole tube with 6 poles and rotates at 1200 rpm. The brushless exciter eliminates the danger of contamination by carbon dust and minimizes maintenance. Semi-conductor rectifiers rotating within the generator / exciter shaft provide excitation for the main generator field.

The generator is a critical component in the availability and reliability of the gas turbine, in that its loss would mean the total loss of the GT generation as well as black start capability for the Holyrood operation.

**Fuel Oil System:** The plant's gas turbine uses No. 2 diesel fuel which is delivered to site by truck. The off-loading pump is located outdoors at the northwest corner of the gas turbine building and has above-ground piping stretching to the bulk storage tanks. The two fuel tanks were fabricated in 1998 to ULC-S601-93 standards, with an above ground doubled wall and have a total storage capacity of 200,000 litres.

The offloading system is comprised of a single 600 volt pump arrangement with local start / stop control. Power for the motor is supplied from the gas turbine MCC control centre. The piping installation is typical with a 3 inch Y strainer, isolation valves and piping to the storage tanks.

Two 100%, 600 volt, centrifugal forwarding pumps provide low pressure No. 2 diesel fuel for the jet engine. The fuel passes through a duplex suction strainer and a 5 micron discharge filter before reaching the jet engine. The fuel line also incorporates a fuel flow / totalizing meter and a fire system trip valve prior to entering the building.

**Governor and Fuel Control:** The standard Avon fuel control system is used without alteration as a basis for the AP1 governing and fuel control system. The throttle valve is used as a generator valve and the H.P. cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply.

Woodward Governor suggests that the present system has a reliability of about 50%. In addition spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

**Control Room & MCC/ Switchgear Room:** Within the gas turbine building, the electrical and control systems consist of a rotating brushless exciter, an automatic voltage regulator (AVR), a start rectifier, PLC control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment. The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960s. The programmable logic controller (PLC), governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit act in combination to supply a controlled DC current to the wound rotor of the main generator which in turn controls its stator terminal voltage (13.8 kV) and Mvar delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the Jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and Mwatt loading. In 1986, the current Gem 80/500 PLC replaced all relay logic and is now the primary controlling medium for the gas turbine. A current assessment undertaken by Hydro Engineering Services will determine the feasibility of replacing or upgrading all the AEI electrical equipment for the Holyrood Gas Turbine

**Excitation System:** The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-13. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

**Switchgear:** Primary voltage generated by the GT (Gas Turbine) is 13,300 Volts. The installed gas turbine capacity is 13.5 MW, however based on limiting factors the unit sees normal operation of ~12 MW. Originally this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT’s) in this breaker. These CT’s are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB12. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

**Fire Protection System:** The fire system is an Ansul Inergen total-flooding type that can operate automatically via fire detection or manually via pull stations. The system is comprised of Inergen storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers. It was installed in 2000 to replace the Halon fire system in respect of the ozone depleting substance regulations.






FIGURE 11-34 GTG BUILDING & LIGHT OIL STORAGE






FIGURE 11-35 LIGHT OIL RECEIVING & LUBE OIL RADIATOR

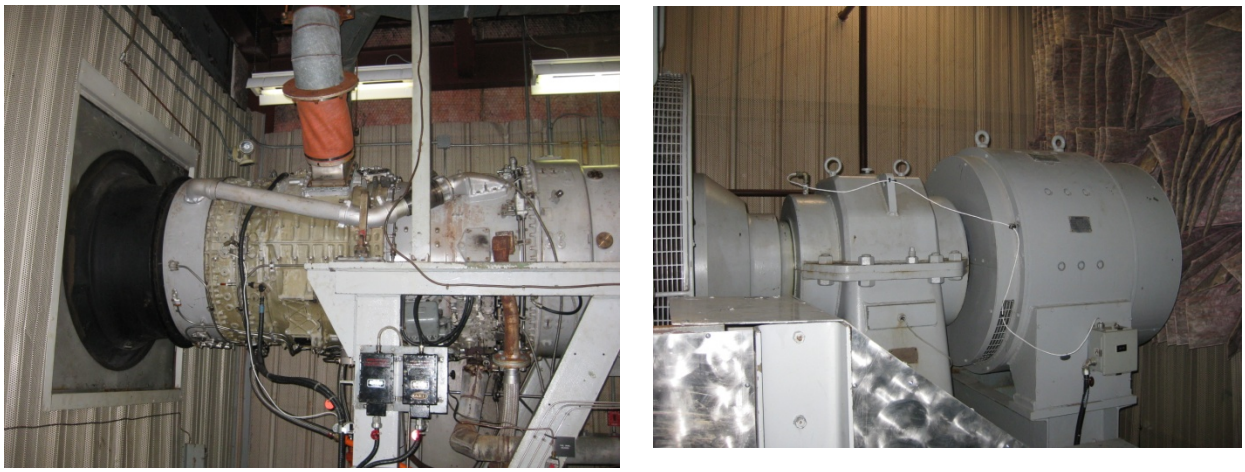


FIGURE 11-36 GTG GAS ENGINE & GENERATOR



FIGURE 11-37 GTG LIGHT OIL RECEIVING

**Compressed Air System:** The compressed air system consists of a single 600 volt motor/compressor unit, a 310 L (82 gallon) storage tank, a Pall instrument air dryer and a small control and monitoring panel. The system is designed to supply 700 kPa instrument air to operate the power turbine snow doors, the main generator exhaust and intake louvers and the jet engine intake and exhaust cooling air louvers. It also has provisions for a four-bottle nitrogen back-up supply in the event of a compressor system failure. The control panel provides pressure indication for the system and a transfer valve to the N2 supply.





**FIGURE 11-38 GTG EXHAUST STACK & DUCT**

**Inspection and Repair History**

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

**16 October 2003**

- Annual boroscope inspection;
- Slight erosion on casing. Reprotect next shop visit;
- Normal amount of carbon build up on nozzle heads;
- Boroscope inspection satisfactory; and
- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

**10 August 2004**

- Annual hot section inspection & failure to start;
- Housing found to have corrosion on struts, will require protective coating next shop visit;
- Air plenum cleaner than last visit, holes still visible in walls;
- Compressor rotor and stator vane blades in dirty condition;
- Normal amount of carbon build up on nozzle heads;
- Slight damage to #7 Combustion Can; and
- Starting motor replaced, due to seizure. (Solved starting issue).

**27 September 2005**

- Annual inspection and boroscope inspection;
- Front Bearing Housing, outer bushes loose;
- Front Bearing Housing, Corrosion/ pitting;
- Corrosion/ Rust found in Plenum;
- HP NGV's have slight erosion of the leading edges and minor cracks in the trailing edges;
- Flame tubes have minor erosion on some of the wiggle strips and some carbon build up within the flame tube, especially around the dish where liquid fuel has collected;
- Normal amount of carbon build up on nozzle heads; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

**13 March 2006**

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

**13 April 2006**

- Fuel oil leak on underside of gas turbine at IGV Ram, seal deterioration.

**25 May 2007**

- AVON repair and boroscope inspection: IGV ram leak, ignitor failure, hot air leak from #6 burner, bellmouth nuts loose, combustion casing boroscope port bolts loose, bleed valve ducting broken and separated, fuel lag at idle and struggling at speed;
- Significant sparking coming from PT splash plate (rubbing shaft). Suggests bearings are worn and thus damaged seal;
- 2 IGV bushes replaced due to wear in the bush. (Majority of bushes and retaining nuts were replaced as well as the locking bush);
- Rebuild of the intake with securing bolts torque and locked;
- IGV ram replaced due to leak;
- Fuel filter replaced due to feed issues;
- Bolts holding PT seal were not tight, seal incorrectly installed;
- Ignitor, lead and box were replaced;
- High fuel consumption noticed at fuel drain valve, suspect worn seals on FCU and fuel pumps;
- Additional breather recommended for rear of gearbox unit, to reduce leaks;
- Compressor section; front bearing housing, inlet guide vanes have significant corrosion and coating loss;
- Combustion cans show signs of cracking, material loss (could lead to further turbine damage);
- IP nozzle guide vanes and HP nozzle guide vanes show signs of cracking on trailing edges;
- Change PT lube oil filters; and
- Replace/ Repair exhaust snow doors.

**21 May 2008**

- Package filtration inspection;
- Plenum survey;
- Windmill inspection of compressor;
- Boroscope of compressor and VIGV;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables);
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades;
- Boroscope inspection: rear of compressor, snout area, combustion can, HP nozzle guide vanes, cooper beams (crooks washers), turbine section;
- PT and gearbox review; and
- Controls review.

**10 June 2008**

- Water pooling noted in intake plenum along with holes in structure and loose debris;
- Compressor showing significant corrosion and pitting on front bearing housing, inlet guide vanes and compressor stages, physical signs of salt evident;
- Combustion cans need to be replaced due to extensive corrosion, #1 and #2 burners removed for inspection. Seized bolts prevented removal of others;
- Hard impact damage evident in turbine stages, suspect debris from combustion cans and/or intake plenum;
- Suggested unit overhaul for blade recoating etc.; and
- Fuel pump and FCU to be repaired.

**15 October 2009**

- Engine removed and placed on site, in vertical stand for repairs (combustion cans);
- Combustion cans were replaced and FCU and fuel pump repaired;
- Loose discharge nozzles, due to broken brackets (2 off) to be replaced in future;
- PT inspection showed signs of light blade rub, none on stators. Diaphragm free of damage;
- PT inlet cone cranks, to be repaired;
- Thermocouple damage, quick fixed. To be upgraded;
- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

**20 November 2009**

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to; low fuel pressure, low oil pressure, incomplete start sequence; determined igniter box malfunction, N2 probe incorrectly connected & FCU actuator tuning;

- Exhaust transition lagging replaced due to fuel saturation;
- Split air manifold cracks, to be repaired; and
- Suggest monitoring setup for the 8 EGT thermocouples.

### 11.2.5.2 Condition Assessment

Essentially the unit is in very poor condition and overdue for a major overhaul of most components. The condition assessment of the gas turbine gensets is as follows in Table 11-46.

**TABLE 11-46 CONDITION ASSESSMENT – GAS TURBINE GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | 1 | 13 | 44 years old and has accumulated about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007 | 4/10 | 150,000 (30) | 1 | 2020 | 2010 | 2011 | No | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | Power Turbine | 2 | 13 | Overdue for overhaul; corrosion/cracking from moisture leakage. | 4/10 | 150,000 (30) | 2 | 2020 | 2010 | 2011 | No | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | Gearbox | 3 | 13 | Overdue for overhaul; corrosion/cracking from moisture leakage. | 4/10 | 150,000 (30) | 2 | 2020 | 2010 | 2011 | No | No | 1969 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | | 4 | 13 | Overdue for overhaul; corrosion/cracking from seaside moisture and starts. | 4/10 | 150,000 (30) | 2 | 2020 | 2010 | 2011 | No | No | 1969 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE SYSTEM | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | | 5 | 13 | Overdue for testing of rotor/stator/auxiliaries. | 4/10 | 200000 (40) | 5 | 2020 | 2010 | 2011 | Yes | No | 1969 |
| 1273 | 7202 | 7310 | 0 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE ELECT & CONTROL | | 6 | 13 | Relatively new. | 4/10 | (15) | 12 | 2020 | 2010 | 2011 | Yes | Yes | 1986 |
| 1273 | 7202 | 7310 | 333927 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE DCS CONTROL | | 7 | 13 | Relatively new. | 4/10 | (15) | 12 | 2020 | 2010 | 2011 | Yes | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Fire System | 8 | 13 | Fire system upgraded to Inergen system in 2000. | 4/10 | (30) | 20 | 2020 | 2010 | N/A | Yes | Yes | 2000 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Exhaust Stack | 9 | 13 | Corroded, leaking, Requires replacement. | 4/10 | (20) | 1 | 2020 | 2010 | 2011 | No | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Radiator | 10 | 13 | Corroded. | 4 | (20) | 3 | 2020 | 2010 | 2011 | Yes | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Fuel delivery | 11 | 13 | Corroded, external pitting. | 4 | (30) | 3 | 2020 | 2010 | 2011 | Yes | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil | 12 | 13 | Overdue for overhaul. | 4 | (30) | 10 | 2020 | 2010 | 2011 | Yes | No | 1986 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | AIR INLET PLENUM CHAMBER | Filter Material | 13 | 13 | Inlet housing and filtration system replaced in 1986. Water leaking; inappropriate material for environment. | 4/10 | (30) | 2 | 2020 | 2010 | 2011 | Yes | No | 1986 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.2.5.3 Actions

Based on the condition assessment, the following actions are recommended for the gas turbine genset.

**TABLE 11-47 RECOMMENDED ACTIONS – GAS TURBINE GENSET**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | 1 | 13 | | | |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & GEARBOX | 2 | 13 | Level 2 assessment in 2010 and/or overhaul in 2011/12. | 2010 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | 3 | 13 | Level 2 assessment in 2010 and/or overhaul in 2011/13. | 2010 | 1 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE SYSTEM | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | 4 | 13 | Level 2 assessment in 2010 and/or overhaul in 2011/14. | 2010 | 1 |
| 1273 | 7202 | 7310 | 0 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE ELECT & CONTROL | 5 | 6,13 | Test in 2014 (6 Year cycle) | 2014 | 2 |
| 1273 | 7202 | 7310 | 333927 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE DCS CONTROL | 6 | 6,13 | No action recommended. | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | 7 | 13 | No action recommended. | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS - STACK | 8 | 13,17 | Conduct Level 2 inspections of the exhaust stack in 2010. | 2010 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS - STACK | 9 | 13,17 | Replace the gas turbine stack and affected roof areas asap. | 2011 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS - INTAKE | 10 | 13,17 | Replace the intake filter system suitable for seaside environment asap. Assess intake structure and corrosion. | 2011 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS - ENCLOSURE | 11 | 13,17 | Expand enclosure and include fuel delivery/rad, etc. | 2011 | 2 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS - Building | 12 | 13,17 | Paint structural members as required, roofing and siding painting. | 2010 | 1 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | AIR INLET PLENUM CHAMBER | 13 | 13,17 | Replace air filter media and repair inlet plenum. | 2011 | 1 |

### 11.2.5.4 Risk Assessment

The risk assessment associated with the gas turbine genset, both from a technological perspective and a safety perspective, is illustrated below in Table 11-48.

**TABLE 11-48 RISK ASSESSMENT – GAS TURBINE GENSET**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Component | RA# | Appendix # | Major Issues | Remaining Life Years (Insufficient Info - Inspection Required Within (x) Years) | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | Likeli--hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | 1 | 13 | Unit failure during system failure - continued system blackout. | 1 | 4 | D | High | 3 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Major overhaul or replacement. |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | GTG Power Turbine | 2 | 13 | Thermo-mechanical failure, foreign object. | 2 | 3 | C | Medium | 3 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and major overhaul or replacement. |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | GTG Gear Box | 3 | 13 | Mechanical failure, seal oil leak. | 2 | 3 | C | Medium | 3 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and major overhaul or replacement. |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | GTG Engine/Compressor | 4 | 13 | Corrosion, thermo-mechanical fatigue. | 2 | 3 | C | Medium | 3 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and major overhaul or replacement. |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | GTG Combustors | 5 | 13 | Corrosion, thermo-mechanical failure. | 5 | 2 | C | Medium | 2 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | New in 2009. Inspection and overhaul or replacement. |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | GTG Combustors | 6 | 13 | Corrosion, thermo-mechanical failure. | 5 | 2 | C | Medium | 2 | C | High | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | New in 2009. Inspection and overhaul or replacement. |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE SYSTEM | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | GTG Generator Exciter | 7 | 13 | Mechanical, electrical failures. | 12 | 2 | C | Low | 2 | B | Low | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and overhaul or replacement. |
| 1273 | 7202 | 7310 | 0 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE ELECT & CONTROL | | 8 | 13 | Not addressed. | 12 | 2 | C | Low | 2 | B | Low | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and maintenance. |
| 1273 | 7202 | 7310 | 333927 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURB DCS CONTROL | | 9 | 13 | Not addressed. | 12 | 1 | C | Low | 2 | B | Low | Loss of generator, potential loss of hydro system, machine damage, safety – personnel. | Inspection and maintenance. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | GTG Exhaust | 10 | 13 | Leaks – end of life. | 1 | 4 | D | High | 4 | C | High | Loss of generator, machine damage, safety – personnel. | Refurbish or replacement asap. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | GTG Lube Oil and Rad | 11 | 13 | Mechanical, leak/fire. | 10 | 3 | B | Medium | 3 | B | Medium | Short loss of generator, equipment damage, safety – personnel. | Refurbish or replacement asap. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | GTG Fuel Oil Receipt, Piping, Feed | 12 | 13 | Mechanical failures. | 3 | 2 | C | Low | 3 | C | High | Temp loss of generator, unit damage, safety – personnel. | Refurbish or replacement asap. |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | AIR INLET PLENUM CHAMBER | GTG Air Intake | 13 | 13 | Leakage salt air. | 2 | 3 | C | High | 3 | B | Medium | Loss of generator, unit damage. | Refurbish or replacement asap. |

### 11.2.5.5 Life Cycle Curve and Remaining Life

Two life cycle curves are presented for the gas turbine system. The first is basically a plot of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing differing representative nominal age limits for various components. It also has several horizontal lines that represent a range of practical equipment life limits in years. The risk area boxes provide an indication of the timing of potential issues either from an age and timing perspective.

The second is a plot of equivalent operating hours of the major parts of the unit impacted by the unit's mode of operation. The chart has several vertical lines representing the overhaul history of the unit. There are three units hours curves. The lowest is the actual hours of operation. The middle curve is the actual hours plus an allowance of twenty equivalent operating hours per start and stop. The highest is the middle value plus an allowance for time spent idle in a seaside harsh environment of 0.3 hours per actual idle hours which was identified for very early units (similar to Holyrood's) as a factor by Siemens

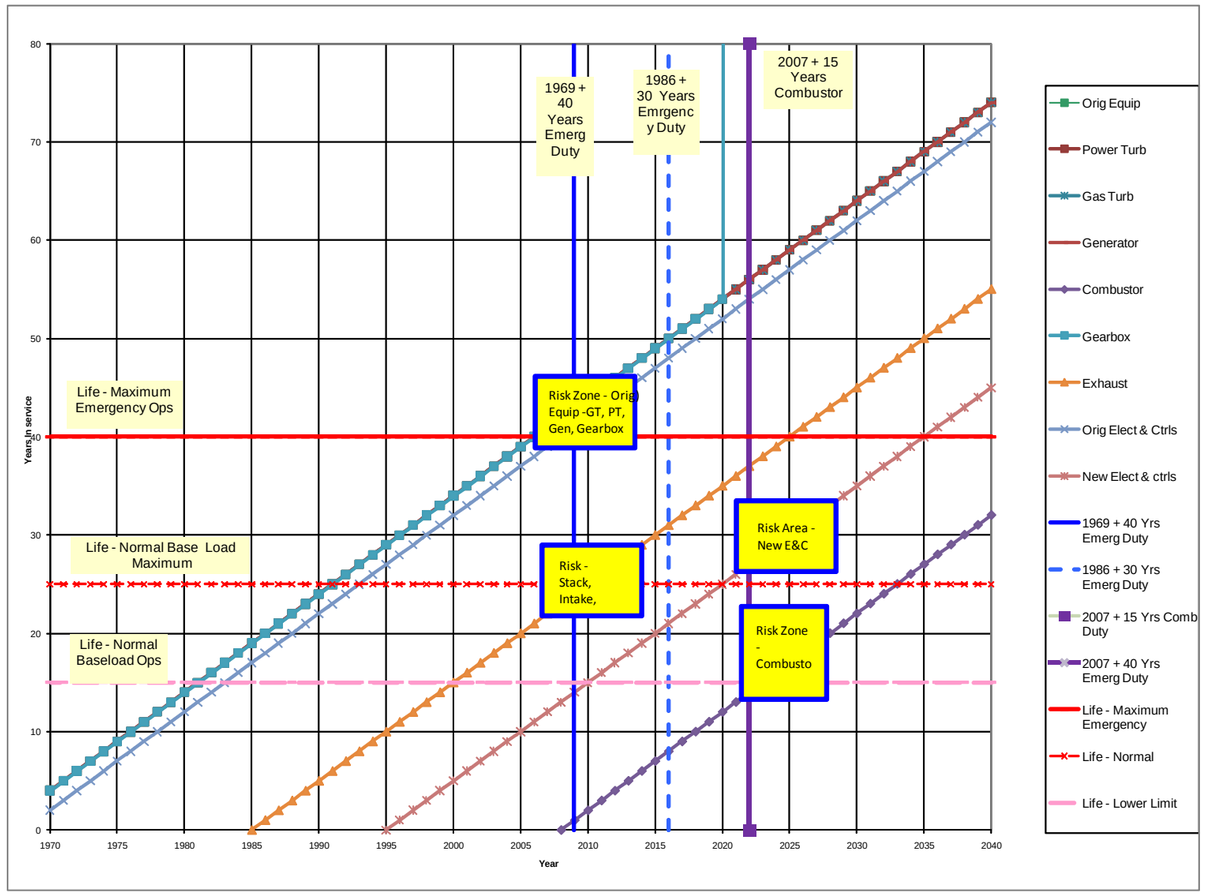



**FIGURE 11-39 LIFE CYCLE CURVE – GAS TURBINE GENSET (PHYSICAL AGE BASIS)**

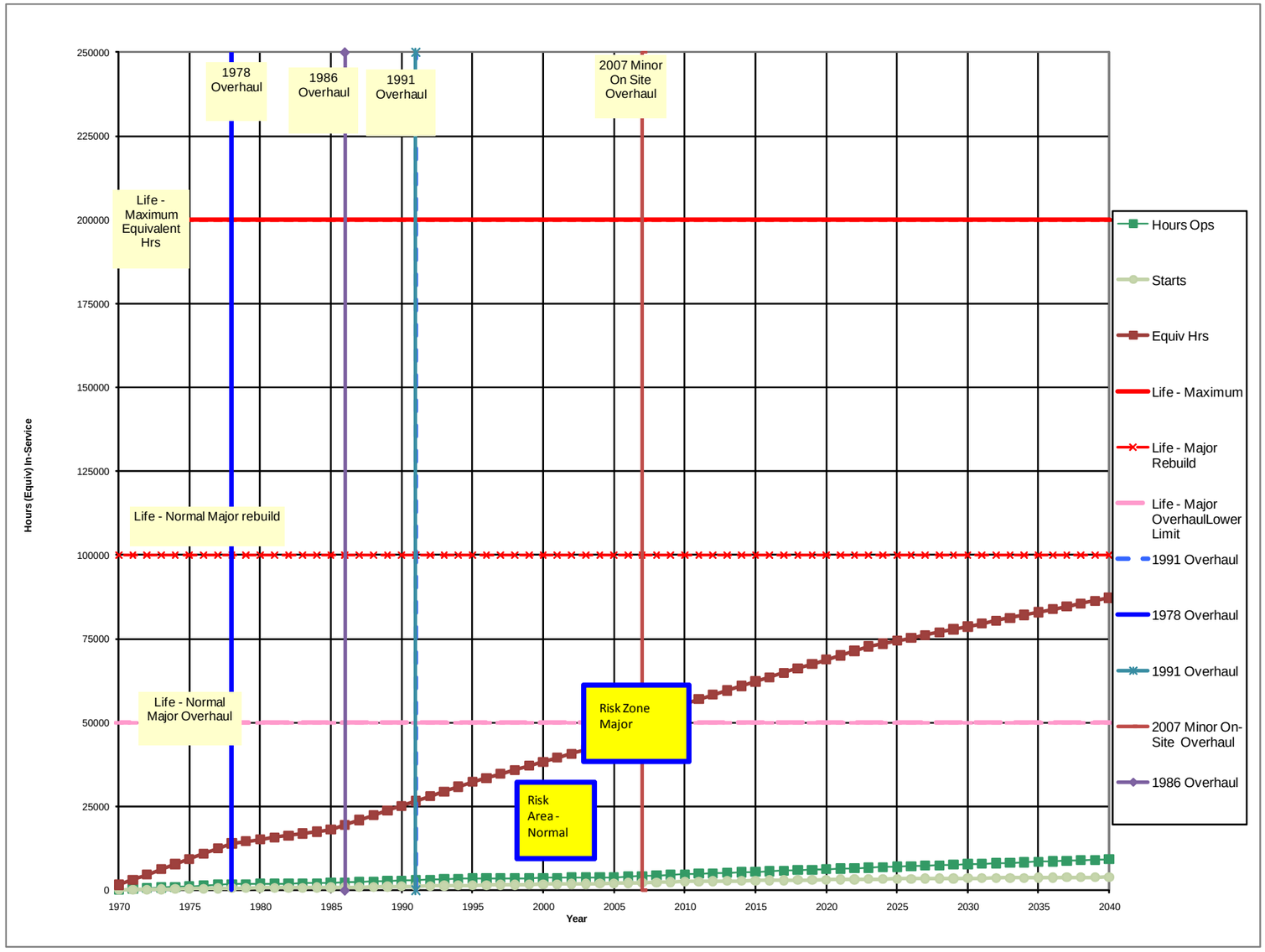



**FIGURE 11-40 LIFE CYCLE CURVE – GAS TURBINE GENSET (EQUIVALENT OPERATING HOURS BASIS)**

The curves, as well as the condition assessment, indicate the unit is in need of a significant and immediate overhaul and refurbishment or replacement. Its remaining life (RL) is less than the desired life (DL) which is 2020. The importance of a near term overhaul or replacement is highlighted by the critical system role that the unit needs to play in black starting the Holyrood units in the event of a system failure. The stack is physically in need of refurbishment or replacement. The intake likely needs a better filter media. The fuel system and coolers need repairs and better ambient protection. The gearbox seals continue to be an issue and a fire safety hazard. The gas turbine has not been overhauled for a considerable period, and recent inspections as well as the life cycle curve for a marine environment suggest that this necessary.

#### 11.2.5.6 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-49 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-49 LEVEL 2 INSPECTION – GAS TURBINE GENSET**

| BU # 1 | Asset # 2 | Asset 3/4 | Description | L2# | Appendix # | Level 2 Work | Year | Priority | Test | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | 1 | 13 | Options Assessment | 2010 | 1 | Options Assessment | $73 |
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | 2 | 13 | On-site Non-invasive inspection supplement to planned boroscope tests | 2010 | 1 | Inspection | $131 |

### 11.2.5.7 Capital Projects

The suggested typical capital enhancements for the gas turbine gensets include:

**TABLE 11-50 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS FOR THE GAS TURBINE GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | 1 | | No capital investment. | | |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | 2 | 13 | Overhaul of power turbine, gearbox. | 2011 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | 3 | 13 | Overhaul gas turbine. | 2011 | 1 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE SYSTEM | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | 4 | | Refurbish generator. | 2015+ | 3 |
| 1273 | 7202 | 7310 | 0 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE ELECT & CONTROL | 5 | 13 | Replace electrical equipment for gas turbine. | 2010 | 1 |
| 1273 | 7202 | 7310 | 333927 | GAS TURBINE SYSTEM | GAS TURBINE ELECT & CONTROL | GAS TURBINE DCS CONTROL | 6 | | No capital investment. | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | 7 | 13 | Replace the exhaust stack. | 2011 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | 8 | 13 | Upgrade fuel receipt and feeding and radiator - enclosure. | 2012 | 2 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | AIR INLET PLENUM CHAMBER | 9 | 13 | Replace air inlet plenum/filter media. | 2011 | 2 |

### 11.2.6 Assets 6717 and 8680 – Diesel Gensets

(Detailed Technical Assessment in Working Papers, Appendix 13)

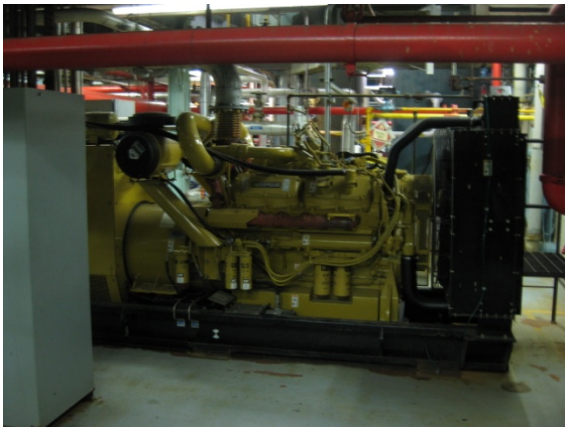
| | |
|---|---|
| Unit #: | HRD COMMON SYSTEMS |
| Asset Class # | BU 1297 Assets Common Gas Turbine |
| SCI & System: | 7199 HRD Common Systems Gas Turbine System |
| Sub-Systems: | 6717 Stage 1 Auxiliary Diesel Generator<br>8680 Stage 2 Auxiliary Diesel Generator |

#### 11.2.6.1 Description

The Stage 1 emergency diesel was replaced in 2007 with a CAT H-6-1F, capable of supplying 635 Kw of 600 volt, 3 phase electrical power for the plant's emergency and back-up systems including the start-up of the gas turbine.

The Stage 2 emergency diesel was installed in 1980. It is at the end of its normal useful life. It should be replaced between 2012 and 2015 and would then be expected to last to 2041.

Both diesel gensets are designed for controlled safe shutdown of Units 1, 2, and 3. They have the necessary auxiliaries (controls, switchgear, cooling, and lubrication) to be stand-alone units. The diesels are redundant and can be operated individually to supply power to the essential services board (600v switchgear) either via a 'dead bus' or a synchronized transfer. Each diesel can supply power to the other essential service board through the use of tie-breakers.



Stage 1 Diesel



Stage 2 Diesel

**FIGURE 11-41 HOLYROOD DIESEL GENSETS**

#### 11.2.6.2 History

| | Stage 1 | Stage 2 |
|---|---|---|
| Manufactured/Delivered | 2007 | 1979 |
| In-Service Date | 2007 | Feb 1980 |
| Replacement (Actual or Planned) | 2007 | 2015 |

The Stage 1 diesel was replaced in 2007, and the Stage 2 diesel is currently planned to be replaced in 2015.

### 11.2.6.3 Condition Assessment

The condition assessment of the diesel gensets is illustrated below in Table 11-51.

**TABLE 11-51 CONDITION ASSESSMENT – DIESEL GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset Level 2 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Append # | Condition | EPRI Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life Required (EOL) | Next Regular Inspection | Next Planned Overhaul/ Major Inspection | Capability to Reach Next Overhaul | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 303240 | 0 | 0 | COMMON SYSTEMS | STAGE 1 AUX.DIESEL GENERATOR | STAGE 1 AUX.DIESEL GENERATOR | N/A | 1 | 13 | New in 2007. Good condition. | 3a | (25) | 20+ | 2041 | 2011 | | No | No | 2007 |
| 1297 | 7199 | 8680 | 0 | 0 | COMMON SYSTEMS | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL GENERATOR | N/A | 2 | 13 | Cummins V-1710-G installed in 1980. Scheduled to be replaced in 2014. | 10 | (30) | 4 | 2041 | 2011 | | Yes | No | 1980 |

Notes:
1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.
2. The “Next Regular Inspection” column identifies a regular inspection (not necessarily an overhaul or detailed Level 2 test) that is currently planned and known to AMEC and which may provide further insight into the equipment life. The “Next Planned Overhaul or Major Inspection” column is intended to identify known detailed inspections and/or overhauls that will definitively update current remaining life assumptions and which are a “Desired Life” stage for condition assessment purposes. Note that where a detailed inspection/overhaul date is highlighted in yellow then it is a specific AMEC recommendation and that date is the basis for conclusions on the ability to make the next detailed inspection/overhaul. Where no specific dates have been identified for “Next Regular Inspection” or “Next Planned Overhaul/Major Inspection”, they are left blank.

### 11.2.6.4 Actions

Based on the condition assessment, the following actions are recommended for the diesel gensets:

**TABLE 11-52 RECOMMENDED ACTIONS – DIESEL GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Action # | App # | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 303240 | 0 | 0 | COMMON | STAGE 1 AUX.DIESEL GENERATOR | STAGE 1 AUX.DIESEL | 4 | 13,6 | New in 2007. No action recommended. | | |
| 1297 | 7199 | 8680 | 0 | 0 | COMMON | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL | 5 | 13,6 | Replace 1980 machine. | 2014 | 1 |

### 11.2.6.5 Risk Assessment

The risk assessment associated with the diesel gensets, both from a technological perspective and a safety perspective, is illustrated below in Table 11-53.

**TABLE 11-53 RISK ASSESSMENT – DIESEL GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | Component | Risk Assess # | Appendix # | Major Issues | Remaining Life Years | Remaining Life | Techno-Eco Risk Assess Model | | | Safety Risk Assess Model | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Comments | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 7199 | 303240 | 0 | 0 | COMMON SYSTEMS | STAGE 1 AUX.DIESEL GENERATOR | STAGE 1 AUX.DIESEL GENERATOR | None | 1 | 13,6 | Mechanical failure during emergency. | 20+ | New in 2007 | 1 | C | Low | 1 | A | Low | Start failure during emergency. | Inspect, maintain. |
| 1297 | 7199 | 8680 | 0 | 0 | COMMON SYSTEMS | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL GENERATOR | None | 2 | 13,6 | Mechanical failure. | 4 | Replacement planned in 2014 | 3 | C | Medium | 3 | A | Low | Start failure during emergency. | End of Life - replace. |

### 11.2.6.6 Life Cycle Curve and Remaining Life

The life cycle curve for the system is illustrated below. Two curves are required to represent the two emergency diesels in the plant. The life curves are plots of physical age of the equipment on the y-axis versus calendar year on the x-axis. The chart has several vertical lines representing representative nominal calendar limits for the engines, with normal life maintenance in an emergency power mode. It also has several horizontal lines that represent a range of practical equipment life limits in years.

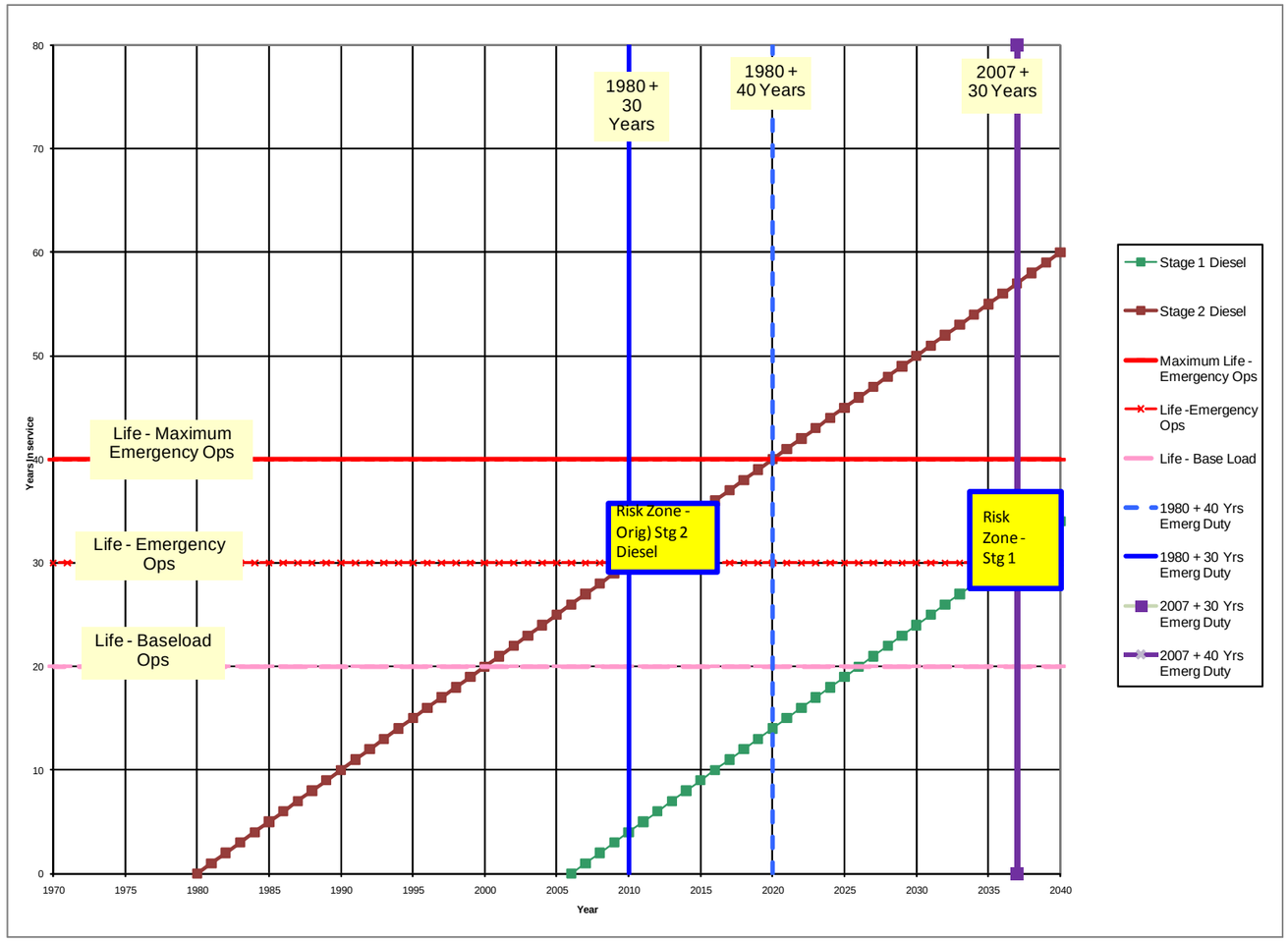



**FIGURE 11-42 LIFE CYCLE CURVE – DIESEL GENSETS**

The curves indicate that the remaining life (RL) of the newer Stage 1 diesel genset exceeds the end date for generation of 2020, and likely the desired life (DL) of 2041 (at the end of synchronous condensing life). It also indicates that the original Stage 2 diesel genset is at or very near its end of life and should be replaced. Given the critical role these units play in emergency safe shutdown, the replacement should be a high priority.

### 11.2.6.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the required Level 2 analyses are provided in Table 11-54 below, assuming the current plant inspection and maintenance program is maintained or improved.

**TABLE 11-54 LEVEL 2 INSPECTION – DIESEL GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | L2# | Appendix # | Level 2 Work | Year | Priority | Cost k$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 303240 | 0 | COMMON SYSTEMS | STAGE 1 AUX.DIESEL GENERATOR | STAGE 1 AUX.DIESEL GENERATOR | N/A | 1 | 13,6 | No Level 2 required. | | | |
| 1297 | 7199 | 8680 | 0 | COMMON SYSTEMS | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL GENERATOR | N/A | 2 | 13 | No Level 2 required. | | | |

### 11.2.6.8 Capital Projects

The suggested typical capital enhancements for the diesel gensets include:

**TABLE 11-55 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – DIESEL GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset 2/3 | Asset 3/4 | Description | CAP# | Appendix # | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 303240 | 0 | 0 | COMMON SYSTEMS | STAGE 1 AUX.DIESEL GENERATOR | STAGE 1 AUX.DIESEL GENERATOR | 1 | 13,6 | No capital required. | | |
| 1297 | 7199 | 8680 | 0 | 0 | COMMON SYSTEMS | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL GENERATOR | 2 | 13,6 | Replace Stage 2 Emergency Diesel, Cummins V-1710-G. | 2014 | 1 |

# 12 LEVEL 2 REQUIREMENTS SUMMARY

Level 2 inspections were identified in Chapters 8 to 11. Summary level information is provided in this chapter. It is summarized by Priorities in Section 12.1 and by Major Plant Area and Priorities in Section 12.2. The costs include all costs identified in the detail sheets below, including contingency and escalation and some allowances for set-up and Holyrood costs.

It should be remembered that the costs include those for the enhanced inspection/overhauls for the steam turbine and generator for Units 1, 2, and 3 in 2012, 2014, and 2016 respectively.

## 12.1 Level 2 Activities Prioritized Summary

Table 12-1 is a summary of Level 2 costs by Priorities assigned by AMEC, with Priority 1 being the highest priority. It is presented as both a breakdown of how the costs were developed (sub-categories) as well as by year.

**TABLE 12-1 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY**

| | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Priority 1 | $17,547 | $10,866 | $543 | $435 | $326 | $652 | $0 | $326 | $0 | $13,148 | $2,630 | $15,777 | $1,770 | $17,547 |
| Priority 2 | $4,811 | $3,093 | $155 | $124 | $93 | $186 | $0 | $93 | $0 | $3,743 | $749 | $4,491 | $320 | $4,811 |
| Priority 3 | $222 | $148 | $7 | $6 | $4 | $9 | $0 | $4 | $0 | $179 | $36 | $215 | $7 | $222 |
| Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $14,107 | $705 | $564 | $423 | $846 | $0 | $423 | $0 | $17,069 | $3,414 | $20,483 | $2,096 | $22,580 |

| | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Priority 1 | $17,547 | $392 | $1,600 | $4,615 | $44 | $6,195 | $13 | $4,687 | $0 |
| Priority 2 | $4,811 | $0 | $773 | $1,879 | $1,929 | $229 | $0 | $0 | $0 |
| Priority 3 | $222 | $0 | $217 | $0 | $0 | $5 | $0 | $0 | $0 |
| Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $392 | $2,590 | $6,494 | $1,973 | $6,429 | $13 | $4,687 | $0 |

## 12.2 Level 2 Activities Prioritized Summary by Major Plant Area

Table 12-2 is a summary of Level 2 costs by Major Plant Area priorities. It is presented as both a breakdown of how the costs were developed (sub-categories) as well as by year. The plant areas are broken down into synchronous condensing required plant equipment (Synch Cond); steam turbine and auxiliaries (Stm Turb) plant equipment required only for electricity generation; boiler and auxiliaries (Blr Stm) plant equipment (boilers and auxiliaries, HP heaters, dearators) required only for electricity generation; switchyard and transformer (Switchy & TS) equipment required for both synchronous condensing and electricity generation; and black start gas turbine and auxiliaries (GTG) equipment and facilities.

TABLE 12-2 LEVEL 2 ACTIVITIES PRIORITIZED SUMMARY BY PLANT AREA

| | Cost k$ | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Synch Cond Priority 1 | $7,894 | $4,933 | $247 | $197 | $148 | $296 | $0 | $148 | $0 | $5,969 | $1,194 | $7,163 | $732 | $7,894 |
| Synch Cond Priority 2 | $594 | $397 | $20 | $16 | $12 | $24 | $0 | $12 | $0 | $480 | $96 | $576 | $17 | $594 |
| Synch Cond Priority 3 | $207 | $138 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $167 | $33 | $200 | $6 | $207 |
| Synch Cond Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 1 | $7,463 | $4,567 | $228 | $183 | $137 | $274 | $0 | $137 | $0 | $5,526 | $1,105 | $6,631 | $832 | $7,463 |
| Stm Turb Priority 2 | $147 | $98 | $5 | $4 | $3 | $6 | $0 | $3 | $0 | $119 | $24 | $142 | $4 | $147 |
| Stm Turb Priority 3 | $15 | $10 | $1 | $0 | $0 | $1 | $0 | $0 | $0 | $12 | $2 | $15 | $0 | $15 |
| Stm Turb Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 1 | $1,758 | $1,076 | $54 | $43 | $32 | $65 | $0 | $32 | $0 | $1,302 | $260 | $1,562 | $196 | $1,758 |
| Blr Stm Prioirity 2 | $4,070 | $2,598 | $130 | $104 | $78 | $156 | $0 | $78 | $0 | $3,144 | $629 | $3,772 | $298 | $4,070 |
| Blr Stm Prioirity 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 1 | $228 | $150 | $8 | $6 | $5 | $9 | $0 | $5 | $0 | $182 | $36 | $218 | $11 | $228 |
| Switchy & TS Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 1 | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| GTG Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $14,107 | $705 | $564 | $423 | $846 | $0 | $423 | $0 | $17,069 | $3,414 | $20,483 | $2,096 | $22,580 |

Table 12-2 Cont'd

| | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Synch Cond Priority 1 | $7,894 | $73 | $1,494 | $2,286 | $0 | $1,961 | $0 | $2,081 | $0 |
| Synch Cond Priority 2 | $594 | $0 | $594 | $0 | $0 | $0 | $0 | $0 | $0 |
| Synch Cond Priority 3 | $207 | $0 | $202 | $0 | $0 | $5 | $0 | $0 | $0 |
| Synch Cond Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 1 | $7,463 | $0 | $100 | $2,311 | $0 | $2,451 | $0 | $2,601 | $0 |
| Stm Turb Priority 2 | $147 | $0 | $147 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 3 | $15 | $0 | $15 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 1 | $1,758 | $0 | $0 | $0 | $0 | $1,758 | $0 | $0 | $0 |
| Blr Stm Prioirity 2 | $4,070 | $0 | $33 | $1,879 | $1,929 | $229 | $0 | $0 | $0 |
| Blr Stm Prioirity 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Prioirity 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 1 | $228 | $116 | $6 | $18 | $44 | $25 | $13 | $6 | $0 |
| Switchy & TS Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 1 | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $22,580 | $392 | $2,590 | $6,494 | $1,973 | $6,429 | $13 | $4,687 | $0 |

Table 12-2 Cont'd

| | | Total Cost k$ | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GAS TURBINE GENERATOR | | | | | | | | | | | | | | | |
| Total | GTG | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Stm Turb | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Stm | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | GTG | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Total Excl Stm Turb | GTG | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Total Excl Blr Stm,Stm Turb | GTG | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | GTG | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | | | | | |
| UNIT 1 | | | | | | | | | | | | | | | |
| Total | U1 | $6,860 | $4,469 | $223 | $179 | $134 | $268 | $0 | $134 | $0 | $5,407 | $1,081 | $6,489 | $371 | $6,860 |
| Stm Turb | U1 | $2,345 | $1,523 | $76 | $61 | $46 | $91 | $0 | $46 | $0 | $1,843 | $369 | $2,211 | $134 | $2,345 |
| Blr Stm Stm | U1 | $1,885 | $1,224 | $61 | $49 | $37 | $73 | $0 | $37 | $0 | $1,481 | $296 | $1,777 | $108 | $1,885 |
| Switchy & TS | U1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U1 | $4,514 | $2,946 | $147 | $118 | $88 | $177 | $0 | $88 | $0 | $3,565 | $713 | $4,278 | $237 | $4,514 |
| Total Excl Blr Stm,Stm Turb | U1 | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U1 | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U1 | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |
| | | | | | | | | | | | | | | | |
| UNIT 2 | | | | | | | | | | | | | | | |
| Total | U2 | $7,158 | $4,462 | $223 | $178 | $134 | $268 | $0 | $134 | $0 | $5,399 | $1,080 | $6,479 | $680 | $7,158 |
| Stm Turb | U2 | $2,620 | $1,613 | $81 | $65 | $48 | $97 | $0 | $48 | $0 | $1,952 | $390 | $2,342 | $278 | $2,620 |
| Blr Stm Stm | U2 | $1,929 | $1,216 | $61 | $49 | $36 | $73 | $0 | $36 | $0 | $1,471 | $294 | $1,766 | $164 | $1,929 |
| Switchy & TS | U2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U2 | $4,538 | $2,849 | $142 | $114 | $85 | $171 | $0 | $85 | $0 | $3,447 | $689 | $4,137 | $401 | $4,538 |
| Total Excl Blr Stm,Stm Turb | U2 | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U2 | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U2 | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |
| | | | | | | | | | | | | | | | |

Table 12-2 Cont'd

| | | Total Cost k$ | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **UNIT 3** | | | | | | | | | | | | | | | |
| Total | U3 | $7,489 | $4,456 | $223 | $178 | $134 | $267 | $0 | $134 | $0 | $5,392 | $1,078 | $6,470 | $1,019 | $7,489 |
| Stm Turb | U3 | $2,659 | $1,539 | $77 | $62 | $46 | $92 | $0 | $46 | $0 | $1,862 | $372 | $2,235 | $424 | $2,659 |
| Blr Stm Stm | U3 | $2,014 | $1,234 | $62 | $49 | $37 | $74 | $0 | $37 | $0 | $1,493 | $299 | $1,792 | $222 | $2,014 |
| Switchy & TS | U3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U3 | $4,830 | $2,917 | $146 | $117 | $88 | $175 | $0 | $88 | $0 | $3,530 | $706 | $4,235 | $594 | $4,830 |
| Total Excl Blr Stm,Stm Turb | U3 | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U3 | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U3 | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |
| | | | | | | | | | | | | | | | |
| **COMMON FACILITIES** | | | | | | | | | | | | | | | |
| Total | Common | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Stm Turb | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Stm | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | Common | $228 | $150 | $8 | $6 | $5 | $9 | $0 | $5 | $0 | $182 | $36 | $218 | $11 | $228 |
| GTG | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | Common | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Total Excl Blr Stm,Stm Turb | Common | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | Common | $641 | $430 | $22 | $17 | $13 | $26 | $0 | $13 | $0 | $520 | $104 | $624 | $17 | $641 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | Common | $641 | $430 | $22 | $17 | $13 | $26 | $0 | $13 | $0 | $520 | $104 | $624 | $17 | $641 |
| | | | | | | | | | | | | | | | |
| **SUMMARY TOTAL** | | | | | | | | | | | | | | | |
| Total | TOTAL | $22,580 | $14,107 | $705 | $564 | $423 | $846 | $0 | $423 | $0 | $17,069 | $3,414 | $20,483 | $2,096 | $22,580 |
| Stm Turb | TOTAL | $7,624 | $4,675 | $234 | $187 | $140 | $281 | $0 | $140 | $0 | $5,657 | $1,131 | $6,788 | $836 | $7,624 |
| Blr Stm Stm | TOTAL | $5,829 | $3,674 | $184 | $147 | $110 | $220 | $0 | $110 | $0 | $4,446 | $889 | $5,335 | $494 | $5,829 |
| Switchy & TS | TOTAL | $228 | $150 | $8 | $6 | $5 | $9 | $0 | $5 | $0 | $182 | $36 | $218 | $11 | $228 |
| GTG | TOTAL | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| Total Excl Stm Turb | TOTAL | $14,955 | $9,432 | $472 | $377 | $283 | $566 | $0 | $283 | $0 | $11,413 | $2,283 | $13,695 | $1,260 | $14,955 |
| Total Excl Blr Stm,Stm Turb | TOTAL | $9,126 | $5,758 | $288 | $230 | $173 | $345 | $0 | $173 | $0 | $6,967 | $1,393 | $8,361 | $766 | $9,126 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | TOTAL | $8,898 | $5,608 | $280 | $224 | $168 | $336 | $0 | $168 | $0 | $6,786 | $1,357 | $8,143 | $755 | $8,898 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | TOTAL | $8,695 | $5,468 | $273 | $219 | $164 | $328 | $0 | $164 | $0 | $6,616 | $1,323 | $7,940 | $755 | $8,695 |

Table 12-2 Cont'd

| | | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| GAS TURBINE GENERATOR | | | | | | | | | | |
| Total | GTG | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Stm | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | GTG | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | GTG | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb | GTG | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | GTG | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | |
| UNIT 1 | | | | | | | | | | |
| Total | U1 | $6,860 | $0 | $821 | $6,038 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb | U1 | $2,345 | $0 | $34 | $2,311 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Stm | U1 | $1,885 | $0 | $6 | $1,879 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | U1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U1 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U1 | $4,514 | $0 | $787 | $3,728 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb | U1 | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U1 | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U1 | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | |
| UNIT 2 | | | | | | | | | | |
| Total | U2 | $0 | $0 | $817 | $0 | $1,929 | $4,412 | $0 | $0 | $0 |
| Stm Turb | U2 | $0 | $0 | $169 | $0 | $0 | $2,451 | $0 | $0 | $0 |
| Blr Stm Stm | U2 | $0 | $0 | $0 | $0 | $1,929 | $0 | $0 | $0 | $0 |
| Switchy & TS | U2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U2 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U2 | $0 | $0 | $648 | $0 | $1,929 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb | U2 | $0 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U2 | $0 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U2 | $0 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |
| | | | | | | | | | | |

Table 12-2 Cont'd

| | | Total k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|
| **UNIT 3** | | | | | | | | | | |
| Total | U3 | $0 | $0 | $383 | $437 | $0 | $1,987 | $0 | $4,681 | $0 |
| Stm Turb | U3 | $0 | $0 | $58 | $0 | $0 | $0 | $0 | $2,601 | $0 |
| Blr Stm Stm | U3 | $0 | $0 | $27 | $0 | $0 | $1,987 | $0 | $0 | $0 |
| Switchy & TS | U3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | U3 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | U3 | $0 | $0 | $325 | $437 | $0 | $1,987 | $0 | $2,081 | $0 |
| Total Excl Blr Stm,Stm Turb | U3 | $0 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | U3 | $0 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | U3 | $0 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |
| | | | | | | | | | | |
| **COMMON FACILITIES** | | | | | | | | | | |
| Total | Common | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Stm Turb | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm Stm | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | Common | $228 | $116 | $6 | $18 | $44 | $25 | $13 | $6 | $0 |
| GTG | Common | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | Common | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Total Excl Blr Stm,Stm Turb | Common | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | Common | $641 | $73 | $564 | $0 | $0 | $5 | $0 | $0 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | Common | $641 | $73 | $564 | $0 | $0 | $5 | $0 | $0 | $0 |
| | | | | | | | | | | |
| **SUMMARY TOTAL** | | | | | | | | | | |
| Total | TOTAL | $7,932 | $392 | $2,590 | $6,494 | $1,973 | $6,429 | $13 | $4,687 | $0 |
| Stm Turb | TOTAL | $2,345 | $0 | $262 | $2,311 | $0 | $2,451 | $0 | $2,601 | $0 |
| Blr Stm Stm | TOTAL | $1,885 | $0 | $33 | $1,879 | $1,929 | $1,987 | $0 | $0 | $0 |
| Switchy & TS | TOTAL | $228 | $116 | $6 | $18 | $44 | $25 | $13 | $6 | $0 |
| GTG | TOTAL | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | TOTAL | $5,587 | $392 | $2,329 | $4,184 | $1,973 | $3,978 | $13 | $2,087 | $0 |
| Total Excl Blr Stm,Stm Turb | TOTAL | $3,702 | $392 | $2,296 | $2,304 | $44 | $1,991 | $13 | $2,087 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS | TOTAL | $3,474 | $276 | $2,290 | $2,286 | $0 | $1,966 | $0 | $2,081 | $0 |
| Total Excl Blr Stm,Stm Turb,Switchy & TS,GTG | TOTAL | $3,271 | $73 | $2,290 | $2,286 | $0 | $1,966 | $0 | $2,081 | $0 |

### 12.2.1 Level 2 Activities – Unit 1

Table 12-3 is a summary of the Level 2 costs identified in Chapter 8 for Unit 1. Charts show both costs broken down into its sub-categories and by year.

**TABLE 12-3 LEVEL 2 ACTIVITIES SUMMARY – UNIT 1**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 0 | 0 | 0 | 0 | 1 | UNIT 1 | | | | | | | | | | | | | | | | | | | |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $67 | $3 | $3 | $2 | $4 | $0 | $2 | $0 | $81 | $16 | $97 | $3 | $100 |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | Outage/Inspection | 2012 | 1 | $1,849 | $1,200 | $60 | $48 | $36 | $72 | $0 | $36 | $0 | $1,452 | $290 | $1,742 | $106 | $1,849 |
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $4 | $3 | $0.2 | $0.1 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $3.6 | $0.7 | $4.4 | $0.1 | $4.5 |
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | Outage/Inspection | 2012 | 1 | $2,311 | $1,500 | $75.0 | $60.0 | $45.0 | $90.0 | $0.0 | $45.0 | $0.0 | $1,815.0 | $363.0 | $2,178.0 | $132.6 | $2,310.6 |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | Borescope Check | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2012 | 2 | $1,433 | $930 | $46.5 | $37.2 | $27.9 | $55.8 | $0.0 | $27.9 | $0.0 | $1,125.3 | $225.1 | $1,350.4 | $82.2 | $1,432.6 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | (Testing of Main Steam, Hot Reheat, Cold Reheat, HP feedwater | 2011 | 1 | $395 | $264 | $13.2 | $10.6 | $7.9 | $15.8 | $0.0 | $7.9 | $0.0 | $319.4 | $63.9 | $383.3 | $11.5 | $394.8 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | Inspection/NDE Test | 2011 | 1 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | Visual Inspion | 2012 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.4 | $6.2 |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | Inspection | 2011 | 2 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | Inspection/NDE Test | 2011 | 2 | $56 | $38 | $1.9 | $1.5 | $1.1 | $2.3 | $0.0 | $1.1 | $0.0 | $45.4 | $9.1 | $54.5 | $1.6 | $56.1 |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | Inspection/NDE Test | 2011 | 2 | $56 | $38 | $1.9 | $1.5 | $1.1 | $2.3 | $0.0 | $1.1 | $0.0 | $45.4 | $9.1 | $54.5 | $1.6 | $56.1 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | Inspection/NDE Test | 2012 | 2 | $216 | $140 | $7.0 | $5.6 | $4.2 | $8.4 | $0.0 | $4.2 | $0.0 | $169.4 | $33.9 | $203.3 | $12.4 | $215.7 |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | Inspection/NDE Test | 2012 | 2 | $225 | $146 | $7.3 | $5.8 | $4.4 | $8.8 | $0.0 | $4.4 | $0.0 | $176.7 | $35.3 | $212.0 | $12.9 | $224.9 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Seawater intake and discharge piping inspection | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test AC water piping thickness | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Inspect heat exchanger | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect concrete pipe to/from pump to condenser | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |

Table 12-3 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Test steel pipe to/from condenser | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Inspection CW intake and discharge structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW intake and discharge structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Inspect Power Centre "A" UAB1, (600 | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 2 | $7 | $5 | $0.3 | $0.2 | $0.2 | $0.3 | $0.0 | $0.2 | $0.0 | $6.1 | $1.2 | $7.3 | $0.2 | $7.5 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 2 | $10 | $7 | $0.4 | $0.3 | $0.2 | $0.4 | $0.0 | $0.2 | $0.0 | $8.5 | $1.7 | $10.2 | $0.3 | $10.5 |

| | Total | Base NDE + AMEC Directs | Scaffold/ Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total | $6,860 | $4,469 | $223 | $179 | $134 | $268 | $0 | $134 | $0 | $5,407 | $1,081 | $6,489 | $371 | $6,860 |
| Stm Turb | $2,345 | $1,523 | $76 | $61 | $46 | $91 | $0 | $46 | $0 | $1,843 | $369 | $2,211 | $134 | $2,345 |
| Blr Stm | $1,885 | $1,224 | $61 | $49 | $37 | $73 | $0 | $37 | $0 | $1,481 | $296 | $1,777 | $108 | $1,885 |
| Switchy & TS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $4,514 | $2,946 | $147 | $118 | $88 | $177 | $0 | $88 | $0 | $3,565 | $713 | $4,278 | $237 | $4,514 |
| Total Excl Blr Stm, Stm Turb | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $2,629 | $1,722 | $86 | $69 | $52 | $103 | $0 | $52 | $0 | $2,084 | $417 | $2,500 | $129 | $2,629 |

Table 12-3 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 0 | 0 | 0 | 0 | 1 | UNIT 1 | | | | | | | | | | | | | | |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $0.0 | $100.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 6696 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR ASSEMBLY | Outage/Inspection | 2012 | 1 | $1,849 | $0.0 | $0.0 | $1,848.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 6733 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $4 | $0.0 | $4.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 0 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE | Outage/Inspection | 2012 | 1 | $2,311 | $0.0 | $0.0 | $2,310.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6729 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6730 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6731 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6732 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | L.P. TURBINE | Borescope Check | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6766 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE RH/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2012 | 2 | $1,433 | $0.0 | $0.0 | $1,432.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 2011 | 1 | $395 | $0.0 | $394.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6699 | 6702 | 6876 | 6902 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER STOP VALVE | Inspection/NDE Test | 2011 | 1 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6699 | 6700 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | Visual Inspion | 2012 | 2 | $6 | $0.0 | $0.0 | $6.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6709 | 6711 | 7056 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FW RESERVE | Inspection | 2011 | 2 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6709 | 6711 | 7059 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 1 | Inspection/NDE Test | 2011 | 2 | $56 | $0.0 | $56.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6709 | 6711 | 7066 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | #1 CONDENSATE & F.W. SYSTEM | LOW PRESSURE HEATER 2 | Inspection/NDE Test | 2011 | 2 | $56 | $0.0 | $56.1 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6709 | 6711 | 7053 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE & F.W. SYSTEM | DEAERATOR SYSTEM | Inspection/NDE Test | 2012 | 2 | $216 | $0.0 | $0.0 | $215.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6709 | 6713 | 0 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | HIGH PRESSURE FEEDWATER SYS | Inspection/NDE Test | 2012 | 2 | $225 | $0.0 | $0.0 | $224.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Seawater intake and discharge piping inspection | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test AC Water piping thickness | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Inspect Heat exchanger | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect Concrete Pipe to/from pump to condenser | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

Table 12-3 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6715 | 270182 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Test steel Pipe to/from condenser | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE | Inspection CW intake and discharge structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6715 | 270182 | 7135 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW intake and discharge structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6723 | 6724 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | GENERATOR BUS DUCT & CONNS | GENERATOR BUS DUCT & CONNS | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Inspect Power Centre "A" UAB1, (600 | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 2 | $7 | $0.0 | $7.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 2 | $10 | $0.0 | $10.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

| | Total | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Total | $6,860 | $0 | $821 | $6,038 | $0 | $0 | $0 | $0 | $0 |
| Stm Turb | $2,345 | $0 | $34 | $2,311 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm | $1,885 | $0 | $6 | $1,879 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $4,514 | $0 | $787 | $3,728 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $2,629 | $0 | $781 | $1,849 | $0 | $0 | $0 | $0 | $0 |

### 12.2.2 Level 2 Activities – Unit 2

Table 12-4 is a summary of the Level 2 costs identified in Chapter 9 for Unit 2. Charts show both costs broken down into its sub-categories and by year.

**TABLE 12-4 LEVEL 2 ACTIVITIES SUMMARY – UNIT 2**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 0 | 0 | 0 | 0 | 2 | UNIT 2 | | | | | | | | | | | | | | | | | | | |
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $4 | $3 | $0.2 | $0.1 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $3.6 | $0.7 | $4.4 | $0.1 | $4.5 |
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $67 | $3.4 | $2.7 | $2.0 | $4.0 | $0.0 | $2.0 | $0.0 | $81.1 | $16.2 | $97.3 | $2.9 | $100.2 |
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | Outage/Inspection | 2014 | 1 | $1,961 | $1,200 | $60.0 | $48.0 | $36.0 | $72.0 | $0.0 | $36.0 | $0.0 | $1,452.0 | $290.4 | $1,742.4 | $218.7 | $1,961.1 |
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | Outage/Inspection | 2014 | 1 | $2,451 | $1,500 | $75.0 | $60.0 | $45.0 | $90.0 | $0.0 | $45.0 | $0.0 | $1,815.0 | $363.0 | $2,178.0 | $273.4 | $2,451.4 |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #1 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | Borescope Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2013 | 2 | $1,476 | $930 | $46.5 | $37.2 | $27.9 | $55.8 | $0.0 | $27.9 | $0.0 | $1,125.3 | $225.1 | $1,350.4 | $125.2 | $1,475.6 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 2011 | 1 | $395 | $264 | $13.2 | $10.6 | $7.9 | $15.8 | $0.0 | $7.9 | $0.0 | $319.4 | $63.9 | $383.3 | $11.5 | $394.8 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STIOP VALVES | Inspection/NDE Test | 2011 | 1 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | Inspection/NDE Test | 2011 | 2 | $57 | 38 | $1.9 | $1.5 | $1.1 | $2.3 | $0.0 | $1.1 | $0.0 | $46.0 | $9.2 | $55.2 | $1.7 | $56.8 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | Inspection/NDE Test | 2011 | 2 | $57 | 38 | $1.9 | $1.5 | $1.1 | $2.3 | $0.0 | $1.1 | $0.0 | $46.0 | $9.2 | $55.2 | $1.7 | $56.8 |

Table 12-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 0 | 0 | 0 | 0 | 2 | UNIT 2 | | | | | | | | | | | | | | | | | | | |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | Inspection | 2011 | 3 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | Inspection/NDE Test | 2013 | 2 | $222 | $140 | $7.0 | $5.6 | $4.2 | $8.4 | $0.0 | $4.2 | $0.0 | $169.4 | $33.9 | $203.3 | $18.8 | $222.1 |
| 1296 | 7635 | 7978 | 8059 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | Inspection/NDE Test | 2013 | 2 | $232 | $146 | $7.3 | $5.8 | $4.4 | $8.8 | $0.0 | $4.4 | $0.0 | $176.7 | $35.3 | $212.0 | $19.7 | $231.6 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test seawater intake and discharge piping | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test AC Water piping thickness | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Inspect Heat exchanger | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect Concrete Pipe to/from pump to condenser | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Test steel Pipe to/from condenser | 2011 | 3 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Inspect CW intake structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW discharge structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 3 | $7 | $5 | $0.3 | $0.2 | $0.2 | $0.3 | $0.0 | $0.2 | $0.0 | $6.1 | $1.2 | $7.3 | $0.2 | $7.5 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 3 | $10 | $7 | $0.4 | $0.3 | $0.2 | $0.4 | $0.0 | $0.2 | $0.0 | $8.5 | $1.7 | $10.2 | $0.3 | $10.5 |

| | Total | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total | $7,158 | $4,462 | $223 | $178 | $134 | $268 | $0 | $134 | $0 | $5,399 | $1,080 | $6,479 | $680 | $7,158 |
| Stm Turb | $2,620 | $1,613 | $81 | $65 | $48 | $97 | $0 | $48 | $0 | $1,952 | $390 | $2,342 | $278 | $2,620 |
| Blr Stm | $1,929 | $1,216 | $61 | $49 | $36 | $73 | $0 | $36 | $0 | $1,471 | $294 | $1,766 | $164 | $1,929 |
| Switchy & TS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $4,538 | $2,849 | $142 | $114 | $85 | $171 | $0 | $85 | $0 | $3,447 | $689 | $4,137 | $401 | $4,538 |
| Total Excl Blr Stm, Stm Turb | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $2,609 | $1,633 | $82 | $65 | $49 | $98 | $0 | $49 | $0 | $1,976 | $395 | $2,371 | $238 | $2,609 |

Table 12-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 0 | 0 | 0 | 0 | 2 | UNIT 2 | | | | | | | | | | | | | | |
| 1296 | 7635 | 7636 | 7664 | 0 | 0 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $4 | $0.0 | $4.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $0.0 | $100.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | Outage/Inspection | 2014 | 1 | $1,961 | $0.0 | $0.0 | $0.0 | $0.0 | $1,961.1 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 0 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE | Outage/Inspection | 2014 | 1 | $2,451 | $0.0 | $0.0 | $0.0 | $0.0 | $2,451.4 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7638 | 0 | 2 | #1 TURBINE | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7643 | 0 | 2 | #2 TURBINE | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7647 | 0 | 2 | #2 TURBINE | TURBINE | TURB REHEAT/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7652 | 0 | 2 | #2 TURBINE | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7658 | 0 | 2 | #2 TURBINE | TURBINE | L.P. TURBINE | Borescope Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2013 | 2 | $1,476 | $0.0 | $0.0 | $0.0 | $1,475.6 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 2011 | 1 | $395 | $0.0 | $394.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7786 | 7810 | 7823 | 322451 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STIOP VALVES | Inspection/NDE Test | 2011 | 1 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7978 | 7992 | 7997 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 1 | Inspection/NDE Test | 2011 | 2 | $57 | $0.0 | $56.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7978 | 7992 | 7998 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | LOW PRESSURE HEATER 2 | Inspection/NDE Test | 2011 | 2 | $57 | $0.0 | $56.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

Table 12-4 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 0 | 0 | 0 | 0 | 2 | UNIT 2 | | | | | | | | | | | | | | |
| 1296 | 7635 | 7978 | 7992 | 8032 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | RESERVE FW SYSTEM | Inspection | 2011 | 3 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7978 | 7992 | 8017 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | L P FEEDWATER SYSTEM | DEAERATOR SYSTEM | Inspection/NDE Test | 2013 | 2 | $222 | $0.0 | $0.0 | $0.0 | $222.1 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 7978 | 8059 | 0 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | Inspection/NDE Test | 2013 | 2 | $232 | $0.0 | $0.0 | $0.0 | $231.6 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test seawater intake and discharge piping | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Test AC Water piping thickness | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Inspect Heat exchanger | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect Concrete Pipe to/from pump to condenser | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 271486 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Test steel Pipe to/from condenser | 2011 | 3 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 271486 | 8095 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Inspect CW intake structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8093 | 271486 | 8120 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW discharge structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8152 | 8153 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | GEN. BUS DUCTS & CONN'S | GEN. BUS DUCTS & CONN'S | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 3 | $7 | $0.0 | $7.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 3 | $10 | $0.0 | $10.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

| | Total | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Total | $7,158 | $0 | $817 | $0 | $1,929 | $4,412 | $0 | $0 | $0 |
| Stm Turb | $2,620 | $0 | $169 | $0 | $0 | $2,451 | $0 | $0 | $0 |
| Blr Stm | $1,929 | $0 | $0 | $0 | $1,929 | $0 | $0 | $0 | $0 |
| Switchy & TS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $4,538 | $0 | $648 | $0 | $1,929 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb | $2,609 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $2,609 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $2,609 | $0 | $648 | $0 | $0 | $1,961 | $0 | $0 | $0 |

### 12.2.3 Level 2 Activities – Unit 3

Table 12-5 is a summary of the Level 2 costs identified in Chapter 10 for Unit 3. Charts show both costs broken down into its sub-categories and by year.

**TABLE 12-5 LEVEL 2 ACTIVITIES SUMMARY – UNIT 3**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 0 | 0 | 0 | 0 | 3 | UNIT 3 | | | | | | | | | | | | | | | | | | | |
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $67 | $3.4 | $2.7 | $2.0 | $4.0 | $0.0 | $2.0 | $0.0 | $81.1 | $16.2 | $97.3 | $2.9 | $100.2 |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | Outage/Inspection | 2016 | 1 | $2,081 | $1,200 | $60.0 | $48.0 | $36.0 | $72.0 | $0.0 | $36.0 | $0.0 | $1,452.0 | $290.4 | $1,742.4 | $338.1 | $2,080.5 |
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | Outage/Inspection | 2016 | 1 | $2,601 | $1,500 | $75.0 | $60.0 | $45.0 | $90.0 | $0.0 | $45.0 | $0.0 | $1,815.0 | $363.0 | $2,178.0 | $422.6 | $2,600.6 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $22 | $15 | $0.8 | $0.6 | $0.5 | $0.9 | $0.0 | $0.5 | $0.0 | $18.2 | $3.6 | $21.8 | $0.7 | $22.4 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2014 | 1 | $1,520 | $930 | $46.5 | $37.2 | $27.9 | $55.8 | $0.0 | $27.9 | $0.0 | $1,125.3 | $225.1 | $1,350.4 | $169.5 | $1,519.8 |
| 1296 | 8193 | 8336 | 8337 | 0 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | Visual Inspion | 2011 | 2 | $3 | $2 | $0.1 | $0.1 | $0.1 | $0.1 | $0.0 | $0.1 | $0.0 | $2.4 | $0.5 | $2.9 | $0.1 | $3.0 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 2012 | 1 | $407 | $264 | $13.2 | $10.6 | $7.9 | $15.8 | $0.0 | $7.9 | $0.0 | $319.4 | $63.9 | $383.3 | $23.3 | $406.7 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | Inspection/NDE Test | 2012 | 1 | $31 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $1.8 | $30.8 |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | Inspection/NDE Test | 2011 | 3 | $105 | $70 | $3.5 | $2.8 | $2.1 | $4.2 | $0.0 | $2.1 | $0.0 | $84.7 | $16.9 | $101.6 | $3.0 | $104.7 |

Table 12-5 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 0 | 0 | 0 | 0 | 3 | UNIT 3 | | | | | | | | | | | | | | | | | | | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | Inspection/NDE Test | 2014 | 2 | $229 | $140 | $7.0 | $5.6 | $4.2 | $8.4 | $0.0 | $4.2 | $0.0 | $169.4 | $33.9 | $203.3 | $25.5 | $228.8 |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | Inspection/NDE Test | 2014 | 1 | $239 | $146 | $7.3 | $5.8 | $4.4 | $8.8 | $0.0 | $4.4 | $0.0 | $176.7 | $35.3 | $212.0 | $26.6 | $238.6 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Test seawater intake and discharge piping | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Test AC Water piping thickness | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Inspect Heat exchanger | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect Concrete Pipe to/from pump to condenser | 2011 | 2 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Inspect CW intake structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW discharge structures and piping | 2011 | 2 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 3 | $7 | $5 | $0.3 | $0.2 | $0.2 | $0.3 | $0.0 | $0.2 | $0.0 | $6.1 | $1.2 | $7.3 | $0.2 | $7.5 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 3 | $10 | $7 | $0.4 | $0.3 | $0.2 | $0.4 | $0.0 | $0.2 | $0.0 | $8.5 | $1.7 | $10.2 | $0.3 | $10.5 |
| | | | | | | | | | | | Total | | $7,489 | $4,456 | $223 | $178 | $134 | $267 | $0 | $134 | $0 | $5,392 | $1,078 | $6,470 | $1,019 | $7,489 |
| | | | | | | | | | | | Stm Turb | | $2,659 | $1,539 | $77 | $62 | $46 | $92 | $0 | $46 | $0 | $1,862 | $372 | $2,235 | $424 | $2,659 |
| | | | | | | | | | | | Blr Stm | | $2,014 | $1,234 | $62 | $49 | $37 | $74 | $0 | $37 | $0 | $1,493 | $299 | $1,792 | $222 | $2,014 |
| | | | | | | | | | | | Switchy & TS | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | GTG | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | Total Excl Stm Turb | | $4,830 | $2,917 | $146 | $117 | $88 | $175 | $0 | $88 | $0 | $3,530 | $706 | $4,235 | $594 | $4,830 |
| | | | | | | | | | | | Total Excl Blr Stm, Stm Turb | | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |
| | | | | | | | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS | | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |
| | | | | | | | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | | $2,816 | $1,683 | $84 | $67 | $50 | $101 | $0 | $50 | $0 | $2,036 | $407 | $2,444 | $372 | $2,816 |

Table 12-5 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 0 | 0 | 0 | 0 | 3 | UNIT 3 | | | | | | | | | | | | | | |
| 1296 | 8193 | 8194 | 8223 | 0 | 0 | 3 | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | Inspection | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | 2011 Pre-Outage Inspection Work Allowance | 2011 | 1 | $100 | $0.0 | $100.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | Outage/Inspection | 2016 | 1 | $2,081 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $2,080.5 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 0 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE | Outage/Inspection | 2016 | 1 | $2,601 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $2,600.6 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8196 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE MAIN STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $22 | $0.0 | $22.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8201 | 0 | 3 | U3 GENERATOR | TURBINE | H.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8206 | 0 | 3 | U3 GENERATOR | TURBINE | TURB REHEAT/IP STEAM CHEST | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8211 | 0 | 3 | U3 GENERATOR | TURBINE | I.P. TURBINE | Vlve/Stud Check | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB LUBE OIL TANK & EQUIP | Thickness/Integrity | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | Outage/Inspection | 2014 | 1 | $1,520 | $0.0 | $0.0 | $0.0 | $0.0 | $1,519.8 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8336 | 8337 | 0 | 0 | 3 | BOILER PLANT | BOILER STRUCTURE | BOILER STRUCTURE | Visual Inspion | 2011 | 2 | $3 | $0.0 | $3.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 0 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER MAIN STEAM LINES | (Testing of Main Steam , Hot Reheat, Cold Reheat, HP feedwater | 2012 | 1 | $407 | $0.0 | $0.0 | $406.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8336 | 8359 | 8372 | 8373 | 3 | BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER STOP VALVE | Inspection/NDE Test | 2012 | 1 | $31 | $0.0 | $0.0 | $30.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8528 | 8546 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | LOW PRESSURE FEEDWATER | Inspection/NDE Test | 2011 | 3 | $105 | $0.0 | $104.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

Table 12-5 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 0 | 0 | 0 | 0 | 3 | UNIT 3 | | | | | | | | | | | | | | |
| 1296 | 8193 | 8528 | 8546 | 8571 | 0 | 3 | CONDENSATE & F.W. SYSTEM | LOW PRESSURE FEEDWATER | DEAERATOR SYSTEM | Inspection/NDE Test | 2014 | 2 | $229 | $0.0 | $0.0 | $0.0 | $0.0 | $228.8 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8528 | 8611 | 0 | 0 | 3 | CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. FEEDWATER SYSTEM | Inspection/NDE Test | 2014 | 1 | $239 | $0.0 | $0.0 | $0.0 | $0.0 | $238.6 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Test seawater intake and discharge piping | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Test AC Water piping thickness | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Inspect Heat exchanger | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 271678 | 0 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW SYSTEM | Inspect Concrete Pipe to/from pump to condenser | 2011 | 2 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 271678 | 8647 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. INTAKE SYSTEM | Inspect CW intake structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8645 | 271678 | 8676 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | C.W. DISCHARGE TO OUTFALL | Inspection CW discharge structures and piping | 2011 | 2 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8712 | 8713 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | GENERATOR BUS DUCT & CONN'S | GENERATOR BUS DUCT & CONN'S | Inspect Generator Bus-Duct and Connections | 2011 | 1 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | Test Control Cables | 2011 | 3 | $7 | $0.0 | $7.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | Test Power Cables | 2011 | 3 | $10 | $0.0 | $10.5 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Total | $7,489 | $0 | $383 | $437 | $0 | $1,987 | $0 | $4,681 | $0 |
| Stm Turb | $2,659 | $0 | $58 | $0 | $0 | $0 | $0 | $2,601 | $0 |
| Blr Stm | $2,014 | $0 | $27 | $0 | $0 | $1,987 | $0 | $0 | $0 |
| Switchy & TS | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $4,830 | $0 | $325 | $437 | $0 | $1,987 | $0 | $2,081 | $0 |
| Total Excl Blr Stm, Stm Turb | $2,816 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $2,816 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $2,816 | $0 | $298 | $437 | $0 | $0 | $0 | $2,081 | $0 |

### 12.2.4 Level 2 Activities – Common Facilities

Table 12-6 is a summary of the Level 2 costs identified in Chapter 11 for Common Facilities. Charts show both costs broken down into its sub-categories and by year.

**TABLE 12-6 LEVEL 2 ACTIVITIES SUMMARY – COMMON FACILITIES**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | Base NDE + AMEC Directs | Scaffold/Inf rast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | | | | | | |
| 1297 | 7199 | 7192 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Inspect E&C Systems | 2011 | 2 | $75 | $50 | $2.5 | $2.0 | $1.5 | $3.0 | $0.0 | $1.5 | $0.0 | $60.5 | $12.1 | $72.6 | $2.2 | $74.8 |
| 1297 | 7199 | 7204 | 7223 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL TRANSFER TO STORAGE | Redesign electric heat trace | 2010 | 1 | $73 | $50 | $2.5 | $2.0 | $1.5 | $3.0 | $0.0 | $1.5 | $0.0 | $60.5 | $12.1 | $72.6 | $0.0 | $72.6 |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | Inspect day tank, light oil tanks, and associated systems | 2011 | 1 | $37 | $25 | $1.3 | $1.0 | $0.8 | $1.5 | $0.0 | $0.8 | $0.0 | $30.3 | $6.1 | $36.3 | $1.1 | $37.4 |
| 1297 | 7199 | 7206 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | Hydrogen, Carbon dioxide, and Nitrogen piping thickness sampling | 2011 | 1 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1297 | 7255 | 272255 | 7283 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Structural walkdown checkPowerhouse | 2014 | 3 | $5 | $3 | $0.2 | $0.1 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $3.6 | $0.7 | $4.4 | $0.5 | $4.9 |
| 1297 | 7255 | 272255 | 7285 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Concrete Testing and stoplog structure inspection | 2011 | 2 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1297 | 7255 | 272255 | 7286 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Concrete Testing and stoplog structure inspection | 2011 | 2 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1297 | 7255 | 272255 | 7305 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Structural and concrete testing building | 2011 | 3 | $37 | $25 | $1.3 | $1.0 | $0.8 | $1.5 | $0.0 | $0.8 | $0.0 | $30.3 | $6.1 | $36.3 | $1.1 | $37.4 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Inspect pipeline | 2011 | 1 | $37 | $25 | $1.3 | $1.0 | $0.8 | $1.5 | $0.0 | $0.8 | $0.0 | $30.3 | $6.1 | $36.3 | $1.1 | $37.4 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | Inspect dam | 2011 | 1 | $22 | $15 | $0.8 | $0.6 | $0.5 | $0.9 | $0.0 | $0.5 | $0.0 | $18.2 | $3.6 | $21.8 | $0.7 | $22.4 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |

Table 12-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | | | | | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $20 | $1.0 | $0.8 | $0.6 | $1.2 | $0.0 | $0.6 | $0.0 | $24.2 | $4.8 | $29.0 | $0.9 | $29.9 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Inspect Clarifier, Sand Filters, Clearwell | 2011 | 1 | $75 | $50 | $2.5 | $2.0 | $1.5 | $3.0 | $0.0 | $1.5 | $0.0 | $60.5 | $12.1 | $72.6 | $2.2 | $74.8 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | Inspect/clean Acid & Caustic Tanks | 2011 | 2 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | OIL/WATER SEPARATORS | Inspect Oil Water Separators | 2011 | 2 | $75 | $50 | $2.5 | $2.0 | $1.5 | $3.0 | $0.0 | $1.5 | $0.0 | $60.5 | $12.1 | $72.6 | $2.2 | $74.8 |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | OIL/WATER SEPARATORS | Check Oily Water & Discharge Pipes | 2011 | 2 | $15 | $10 | $0.5 | $0.4 | $0.3 | $0.6 | $0.0 | $0.3 | $0.0 | $12.1 | $2.4 | $14.5 | $0.4 | $15.0 |
| 1297 | 9739 | 10038 | 99003527 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | CONCRETE BASINS FOR W.W.T.S. | Concrete testing basin tanks | 2011 | 3 | $18 | $12 | $0.6 | $0.5 | $0.4 | $0.7 | $0.0 | $0.4 | $0.0 | $14.5 | $2.9 | $17.4 | $0.5 | $17.9 |
| 1325 | 5975 | 5975 | 303236 | HRDTS | TRANSFORMERS | T1 Power Transformer | Elect Test & insp | 2014 | 1 | $18 | $11 | $0.6 | $0.4 | $0.3 | $0.7 | $0.0 | $0.3 | $0.0 | $13.3 | $2.7 | $16.0 | $2.0 | $18.0 |
| 1325 | 5976 | 5976 | 61-00-69225 | HRDTS | TRANSFORMERS | T2 Power Transformer | Elect Test & insp | 2013 | 1 | $18 | $12 | $0.6 | $0.5 | $0.3 | $0.7 | $0.0 | $0.3 | $0.0 | $13.9 | $2.8 | $16.7 | $1.5 | $18.2 |
| 1325 | 5977 | 5977 | 287198 | HRDTS | TRANSFORMERS | T3 Power Transformer | Elect Test & insp | 2016 | 1 | $6 | $4 | $0.2 | $0.1 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.2 | $0.8 | $5.1 | $1.0 | $6.1 |
| 1325 | 5978 | 5978 | 287199 | HRDTS | TRANSFORMERS | Transformer T4 (spare) | Elect Test & insp | 2011 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.2 | $6.0 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDTS | TRANSFORMERS | Transformer T5 | Elect Test & insp | 2015 | 1 | $7 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.9 | $6.7 |
| 1325 | 5980 | 5980 | 287065 | HRDTS | TRANSFORMERS | Transformer T6 | Elect Test & insp | 2013 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.5 | $6.3 |
| 1325 | 5981 | 5981 | 287064 | HRDTS | TRANSFORMERS | Transformer T7 | Elect Test & insp | 2013 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.5 | $6.3 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDTS | TRANSFORMERS | Transformer T8 | Elect Test & insp | 2014 | 1 | $7 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.7 | $6.5 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDTS | TRANSFORMERS | Transformer T9 | Elect Test & insp | 2012 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.4 | $6.2 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDTS | TRANSFORMERS | Transformer T10 | Elect Test & insp | 2012 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.4 | $6.2 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Service Power System, UST-1 Transformer | Elect Test & insp | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Service Power System, UST-2 Transformer | Elect Test & insp | 2013 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.5 | $6.3 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Unit Service Power System, UST-3 Transformer | Elect Test & insp | 2013 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.5 | $6.3 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDTS | TRANSFORMERS | Stage 1, Station Service Power. SST-12 Trans. | Elect Test & insp | 2015 | 1 | $7 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.9 | $6.7 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDTS | TRANSFORMERS | Stage 2, Station Service Power, SST-34 Trans. | Elect Test & insp | 2012 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.4 | $6.2 |

Table 12-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | Base NDE + AMEC Directs | Scaffold/Inf rast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | | | | | | |
| 1325 | 6016 | 6016 | 991110 | HRDTS | TRANSFORMERS | T1 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $17 | $12 | $0.6 | $0.5 | $0.4 | $0.7 | $0.0 | $0.4 | $0.0 | $15 | $2.9 | $17 | $0.0 | $17.4 |
| 1325 | 6017 | 6017 | 991110 | HRDTS | TRANSFORMERS | T2 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $17 | $12 | $0.6 | $0.5 | $0.4 | $0.7 | $0.0 | $0.4 | $0.0 | $15 | $2.9 | $17 | $0.0 | $17.4 |
| 1325 | 6018 | 6018 | 991110 | HRDTS | TRANSFORMERS | T3 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $5 | $1.0 | $6 | $0.0 | $5.8 |
| 1325 | 6019 | 6019 | 991110 | HRDTS | TRANSFORMERS | Transformer T4 (spare) | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6020 | 6020 | 991110 | HRDTS | TRANSFORMERS | Transformer T5 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6021 | 6021 | 991110 | HRDTS | TRANSFORMERS | Transformer T6 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6022 | 6022 | 991110 | HRDTS | TRANSFORMERS | Transformer T7 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6023 | 6023 | 991110 | HRDTS | TRANSFORMERS | Transformer T8 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6024 | 6024 | 991110 | HRDTS | TRANSFORMERS | Transformer T9 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6025 | 6025 | 991110 | HRDTS | TRANSFORMERS | Transformer T10 | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6026 | 6026 | 991110 | HRDTS | TRANSFORMERS | Service Power System, UST-1 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6027 | 6027 | 991110 | HRDTS | TRANSFORMERS | Service Power System, UST-2 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6028 | 6028 | 991110 | HRDTS | TRANSFORMERS | Unit Service Power System, UST-3 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6029 | 6029 | 991110 | HRDTS | TRANSFORMERS | Stage 1, Station Service Power. SST-12 Trans. | Gas in Oil test & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |
| 1325 | 6030 | 6030 | 991110 | HRDTS | TRANSFORMERS | Stage 2, Station Service Power, SST-34 Trans. | Gas in Oil & checks | 2010 | 1 | $6 | $4 | $0.2 | $0.2 | $0.1 | $0.2 | $0.0 | $0.1 | $0.0 | $4.8 | $1.0 | $5.8 | $0.0 | $5.8 |

| | Total | Base NDE + AMEC Directs | Scaffold/Inf rast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Stm Turb | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | $228 | $150 | $8 | $6 | $5 | $9 | $0 | $5 | $0 | $182 | $36 | $218 | $11 | $228 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Total Excl Blr Stm, Stm Turb | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $641 | $430 | $22 | $17 | $13 | $26 | $0 | $13 | $0 | $520 | $104 | $624 | $17 | $641 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $641 | $430 | $22 | $17 | $13 | $26 | $0 | $13 | $0 | $520 | $104 | $624 | $17 | $641 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Priority 1 | $600 | $400 | $20 | $16 | $12 | $24 | $0 | $12 | $0 | $484 | $97 | $581 | $19 | $600 |
| Priority 2 | $209 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $6 | $209 |
| Priority 3 | $60 | $40 | $2 | $2 | $1 | $2 | $0 | $1 | $0 | $48 | $10 | $58 | $2 | $60 |
| Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $870 | $580 | $29 | $23 | $17 | $35 | $0 | $17 | $0 | $702 | $140 | $842 | $27 | $870 |

Table 12-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | |
| 1297 | 7199 | 7192 | 0 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Inspect E&C Systems | 2011 | 2 | $75 | $0.0 | $74.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7199 | 7204 | 7223 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL TRANSFER TO STORAGE | Redesign electric heat trace | 2010 | 1 | $73 | $72.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7199 | 7204 | 7224 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL STORAGE & PIPING | Inspect day tank, light oil tanks, and associated systems | 2011 | 1 | $37 | $0.0 | $37.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7199 | 7206 | 0 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | GAS STORAGE SYSTEMS | Hydrogen, Carbon dioxide, and Nitrogen piping thickness sampling | 2011 | 1 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7255 | 272255 | 7283 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Structural walkdown checkPowerhouse | 2014 | 3 | $5 | $0.0 | $0.0 | $0.0 | $0.0 | $4.9 | $0.0 | $0.0 | $0.0 |
| 1297 | 7255 | 272255 | 7285 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Concrete Testing and stoplog structure inspection | 2011 | 2 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7255 | 272255 | 7286 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Concrete Testing and stoplog structure inspection | 2011 | 2 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 7255 | 272255 | 7305 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Structural and concrete testing building | 2011 | 3 | $37 | $0.0 | $37.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | RAW WATER SYSTEM | Inspect pipeline | 2011 | 1 | $37 | $0.0 | $37.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 7210 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | QUARRY BROOK DAM & FISHWAY SYS | Inspect dam | 2011 | 1 | $22 | $0.0 | $22.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

Table 12-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 286053 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | Inspect/test ploisher | 2011 | 1 | $30 | $0.0 | $29.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | WATER TREATMENT PLANT SYSTEMS | Inspect Clarifier, Sand Filters, Clearwell | 2011 | 1 | $75 | $0.0 | $74.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 7203 | 286057 | WATER TREATMENT &ENVIRONMT | WATER TREATMENT PLANT | W.T.P. SULFURIC ACID SYSTEM | Inspect/clean Acid & Caustic Tanks | 2011 | 2 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | OIL/WATER SEPARATORS | Inspect Oil Water Separators | 2011 | 2 | $75 | $0.0 | $74.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 10038 | 7263 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | OIL/WATER SEPARATORS | Check Oily Water & Discharge Pipes | 2011 | 2 | $15 | $0.0 | $15.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1297 | 9739 | 10038 | 99003527 | WATER TREATMENT &ENVIRONMT | WASTE WATER TREATMNT SYSTM | CONCRETE BASINS FOR W.W.T.S. | Concrete testing basin tanks | 2011 | 3 | $18 | $0.0 | $17.9 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5975 | 5975 | 303236 | HRDTS | TRANSFORMERS | T1 Power Transformer | Elect Test & insp | 2014 | 1 | $18 | $0.0 | $0.0 | $0.0 | $0.0 | $18.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5976 | 5976 | 61-00-69225 | HRDTS | TRANSFORMERS | T2 Power Transformer | Elect Test & insp | 2013 | 1 | $18 | $0.0 | $0.0 | $0.0 | $18.2 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5977 | 5977 | 287198 | HRDTS | TRANSFORMERS | T3 Power Transformer | Elect Test & insp | 2016 | 1 | $6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $6.1 | $0.0 |
| 1325 | 5978 | 5978 | 287199 | HRDTS | TRANSFORMERS | Transformer T4 (spare) | Elect Test & insp | 2011 | 1 | $6 | $0.0 | $6.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDTS | TRANSFORMERS | Transformer T5 | Elect Test & insp | 2015 | 1 | $7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $6.7 | $0.0 | $0.0 |
| 1325 | 5980 | 5980 | 287065 | HRDTS | TRANSFORMERS | Transformer T6 | Elect Test & insp | 2013 | 1 | $6 | $0.0 | $0.0 | $0.0 | $6.3 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5981 | 5981 | 287064 | HRDTS | TRANSFORMERS | Transformer T7 | Elect Test & insp | 2013 | 1 | $6 | $0.0 | $0.0 | $0.0 | $6.3 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDTS | TRANSFORMERS | Transformer T8 | Elect Test & insp | 2014 | 1 | $7 | $0.0 | $0.0 | $0.0 | $0.0 | $6.5 | $0.0 | $0.0 | $0.0 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDTS | TRANSFORMERS | Transformer T9 | Elect Test & insp | 2012 | 1 | $6 | $0.0 | $0.0 | $6.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDTS | TRANSFORMERS | Transformer T10 | Elect Test & insp | 2012 | 1 | $6 | $0.0 | $0.0 | $6.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Service Power System, UST-1 Transformer | Elect Test & insp | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Service Power System, UST-2 Transformer | Elect Test & insp | 2013 | 1 | $6 | $0.0 | $0.0 | $0.0 | $6.3 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 991000 | 991100 | 991110 | SWITCHYARD | TRANSFORMERS | Unit Service Power System, UST-3 Transformer | Elect Test & insp | 2013 | 1 | $6 | $0.0 | $0.0 | $0.0 | $6.3 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDTS | TRANSFORMERS | Stage 1, Station Service Power. SST-12 Trans. | Elect Test & insp | 2015 | 1 | $7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $6.7 | $0.0 | $0.0 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDTS | TRANSFORMERS | Stage 2, Station Service Power, SST-34 Trans. | Elect Test & insp | 2012 | 1 | $6 | $0.0 | $0.0 | $6.2 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

Table 12-6 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset 2/3 | Asset 3/4 | Description | Sub System Comment | Year | Priority | Cost | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 0 | 0 | COMMON SYSTEMS | COMMON SYSTEMS | | | | | | | | | | | | | |
| 1325 | 6016 | 6016 | 991110 | HRDTS | TRANSFORMERS | T1 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $17 | $17.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6017 | 6017 | 991110 | HRDTS | TRANSFORMERS | T2 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $17 | $17.4 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6018 | 6018 | 991110 | HRDTS | TRANSFORMERS | T3 Power Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6019 | 6019 | 991110 | HRDTS | TRANSFORMERS | Transformer T4 (spare) | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6020 | 6020 | 991110 | HRDTS | TRANSFORMERS | Transformer T5 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6021 | 6021 | 991110 | HRDTS | TRANSFORMERS | Transformer T6 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6022 | 6022 | 991110 | HRDTS | TRANSFORMERS | Transformer T7 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6023 | 6023 | 991110 | HRDTS | TRANSFORMERS | Transformer T8 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6024 | 6024 | 991110 | HRDTS | TRANSFORMERS | Transformer T9 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6025 | 6025 | 991110 | HRDTS | TRANSFORMERS | Transformer T10 | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6026 | 6026 | 991110 | HRDTS | TRANSFORMERS | Service Power System, UST-1 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6027 | 6027 | 991110 | HRDTS | TRANSFORMERS | Service Power System, UST-2 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6028 | 6028 | 991110 | HRDTS | TRANSFORMERS | Unit Service Power System, UST-3 Transformer | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6029 | 6029 | 991110 | HRDTS | TRANSFORMERS | Stage 1, Station Service Power. SST-12 Trans. | Gas in Oil test & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1325 | 6030 | 6030 | 991110 | HRDTS | TRANSFORMERS | Stage 2, Station Service Power, SST-34 Trans. | Gas in Oil & checks | 2010 | 1 | $6 | $5.8 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |

| | Total | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|
| Total | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Stm Turb | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Blr Stm | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Switchy & TS | $228 | $116 | $6 | $18 | $44 | $25 | $13 | $6 | $0 |
| GTG | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Excl Stm Turb | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Total Excl Blr Stm, Stm Turb | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS | $641 | $73 | $564 | $0 | $0 | $5 | $0 | $0 | $0 |
| Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | $641 | $73 | $564 | $0 | $0 | $5 | $0 | $0 | $0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Priority 1 | $600 | $189 | $305 | $18 | $44 | $25 | $13 | $6 | $0 |
| Priority 2 | $209 | $0 | $209 | $0 | $0 | $0 | $0 | $0 | $0 |
| Priority 3 | $60 | $0 | $55 | $0 | $0 | $5 | $0 | $0 | $0 |
| Priority 4 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total | $870 | $189 | $570 | $18 | $44 | $29 | $13 | $6 | $0 |

### 12.2.5 Level 2 Activities – Gas Turbine Generator

Table 12-7 is a summary of the Level 2 costs identified in Chapter 11 for the Gas Turbine Generator Unit. Charts show both costs broken down into its sub-categories and by year.

**TABLE 12-7 LEVEL 2 ACTIVITIES SUMMARY – GAS TURBINE GENERATOR**

| BU # 1 | Asset # 2 | Asset 3/4 | Description | Level II Work | Year | Priority | Cost k$ | Base NDE + AMEC Directs | Scaffold/Infrast | HTGS Costs | OEM Supp | PM NDE | Software Check | Mob & Demob | Fit for Serv Rep | Sub-Total | Conting | Total 2010 | Escal | Total Esc $ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | Options Assessment | 2010 | 1 | $73 | $50 | $3 | $2 | $2 | $3 | $0 | $2 | $0 | $61 | $12 | $73 | $0 | $73 |
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | On-site Non-invasive inspection supplement to planned boroscope tests | 2010 | 1 | $131 | $90 | $5 | $4 | $3 | $5 | $0 | $3 | $0 | $109 | $22 | $131 | $0 | $131 |
| | | | | | Total | | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| | | | | | Stm Turb | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Blr Stm | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Switchy & TS | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | GTG | | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| | | | | | Total Excl Stm Turb | | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| | | | | | Total Excl Blr Stm, Stm Turb | | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS | | $203 | $140 | $7 | $6 | $4 | $8 | $0 | $4 | $0 | $169 | $34 | $203 | $0 | $203 |
| | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Table 12-7 Cont'd

| BU # 1 | Asset # 2 | Asset 3/4 | Description | Level II Work | Year | Priority | Cost k$ | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | Options Assessment | 2010 | 1 | $73 | $72.6 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| 1273 | 7202 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | On-site Non-invasive inspection supplement to planned boroscope tests | 2010 | 1 | $131 | $130.7 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| | | | | | Total | | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Stm Turb | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Blr Stm | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Switchy & TS | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | GTG | | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Total Excl Stm Turb | | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Total Excl Blr Stm, Stm Turb | | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS | | $203 | $203 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | Total Excl Blr Stm, Stm Turb, Switchy & TS, GTG | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

# 13 SUMMARY CAPITAL PLAN

A number of suggested capital items were identified in the course of the work, although no attempt was made to quantify the costs. A summary of these capital plan suggestions are presented in two tables – Key Systems Required for Synchronous Condensing Operation to 2041 and Lower Priority Systems, which are primarily related to the steam side of the facility. For details, the reader is referred to the specific systems/equipment assessments in Sections 8 to 11 and the appendices.

## 13.1 Key Systems for Synchronous Condensing Operation

### 13.1.1 Unit 1

**TABLE 13-1 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 1**

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6696 | 6840 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Recommend ordering Stator windings in 2011 for rewinding Stator in 2012. Installation in 2012 subject to techno-economic optimization results. | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271310 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITER | Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system. | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6849 | 271311 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | EXCITATION TRANSFORMER | Replace rectifying transformer | 2013 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 0 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GEN. HYDROGEN GAS SYSTEM | Install hydrogen consumption “totalizer” in each hydrogen supply line | 2011 | 1 |
| 1296 | 6690 | 6691 | 6696 | 6850 | 6806 | 1 | #1 TURBINE & GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | Replace/Overhaul Seal Oil skids re SC Operation | 2015 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6695 | 6805 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURB. LUBE OIL PURIFICATION | Replace turbine lube oil conditioners | 2013 | 1 |
| 1296 | 6690 | 6699 | 6707 | 0 | 0 | 1 | #1 BOILER PLANT | BLR AUX STM & COND SYSTEM | BLR AUX STM & COND SYSTEM | New building heating system | 2015-2020 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7134 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW INTAKE | Clean and coat AC Water pipes | 2012 | 2 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Add system for synchronous condensing similar to Unit 3. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | Implement study to migrate Governor System and Burner Management to DCS - remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. | 2014 | 2 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Change all protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker A1, secondary of transformer AT-A.<br>- Replacement of trip unit on breaker A3, Lighting Transformer LT-A feeder. | 2011 | 1 |
| 1296 | 6690 | 6723 | 6726 | 7182 | 0 | 1 | #1 UNIT GENERATION SERVICES | UNIT SERVICE POWER SYSTEM | POWER CENTRE A | Conduct a complete overhaul to an “as new condition” or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Use spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2012 | 1 |

Table 13-1 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6723 | 6728 | 99043229 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY BANK | Replace Units 1/2, 129VDC Battery Charger 2 with a new Primax Charger alongside in 2010. | 2010 | 2 |
| 1296 | 6690 | 6723 | 6728 | 99043230 | 0 | 1 | #1 UNIT GENERATION SERVICES | BATTERY CHARGERS | 250 VOLT DC BATTERY CHARGE | Replace Unit 1, 258VDC Panel and breakers | 2010 | 2 |
| 1296 | 6690 | 6723 | 7184 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C2 | TURBINE & BOILER AREA MCC C2 | Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC. | 2012 | 1 |
| 1296 | 6690 | 6723 | 7186 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE & BOILER AREA MCC C3 | TURBINE & BOILER AREA MCC C3 | Address issues of MCC's C1, C2, C3, E1 (GE) and GPB34, SDB34 (Siemens) available fault currents exceeding the rating of the short circuit protection devices within the individual wrappers of each MCC. | 2012 | 1 |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER#1 | UPS INVERTER | Overhaul/upgrade unit to extend the life expectancy to at least 2020 | 2012 | 1 |
| 1296 | 6690 | 6723 | 7193 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | UPS INVERTER#1 | UPS INVERTER | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 4,5,6,7,8,9,10,11 off site if necessary with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Replace existing breakers 1, 2 and 3 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB1-12) can be for the new U1 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacements for ITE, 4160V, Type 5HK). Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breaker that might be used. One RPR2 would service U1 and U2 needs. | 2012 | 1 |
| 1296 | 6690 | 6723 | 270295 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | SWITCHGEAR 4160/600V | SWITCHGEAR 4160/600V | Implement changes to this Switchgear, 4160V/600V relaying in UB1modernization study (5.3.2.2 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2012 | 2 |
| 1296 | 6690 | 6723 | 270296 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CABLE RACEWAYS | CABLE RACEWAYS | Install new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270297 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | CONTROL CABLES | CONTROL CABLES | Install new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 270298 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | POWER CABLES | POWER CABLES | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 6690 | 6723 | 309894 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | 600 V Meltric Plugs | 600 V Meltric Plugs | Complete the NLH program of 600V, 3ph, plugs and receptacles on the four Pump feeders left to modify, two on Unit 1 and two on Unit 2 to the LP Drains Pumps. | 2010 | 3 |

### 13.1.2 Unit 2

TABLE 13-2 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 2

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7753 | 0 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR | Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2014 | 2014 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7759 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR STATOR | Recommend ordering stator windings in 2013 for rewinding stator in 2014. Installation in 2014 subject to techno-economic optimization results. | 2013 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GEN HYDROGEN GAS SYSTEM | Install a hydrogen consumption “totalizer” in each hydrogen supply line. | 2011 | 1 |
| 1296 | 7635 | 7636 | 7753 | 7768 | 7732 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | GENERATOR SEAL OIL SYSTEM | Replace/Overhaul Seal Oil skids re SC Operation | 2015 | 1 |
| 1296 | 7635 | 7636 | 7753 | 99034724 | 0 | 2 | U2 GENERATOR | GENERATOR ASSEMBLY | PARTIAL DISCHARGE ANALYSIS SYS | Repair | 2010 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271322 | 0 | 2 | U2 GENERATOR | GENERATOR EXCITATION SYSTEM | EXCITER | Upgrade Static Exciter controls compatible with the latest Unitrol 6000 system | 2013 | 1 |
| 1296 | 7635 | 7636 | 7767 | 271324 | 0 | 2 | #2 TURBINE | TURBINE | EXCITATION TRANSFORMER | Replace rectifying transformer | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Replace turbine lube oil conditioners | 2013 | 1 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Clean and coat AC Water pipes | 2012 | 2 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE OIL SYSTEMS | Provide concrete curbing around turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine system requirements during synchronous generation operation | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE OIL TANK & EQUIP | Replace turbine lube oil conditioners. | 2013 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | DUPLEX FILTER FOR LUBE OIL | Provide mechanical level switches in full flow lube oil filter compartment to detect leaks. | 2013 | 2 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE AC OIL P/P NORTH | Provide electrical control (both “On” and “Off”) for the lube oil pumps in parallel with the local controls in the Control Room | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURB LUBE AC OIL P/P SOUTH | Provide electrical control (both “On” and “Off”) for the lube oil pumps in parallel with the local controls in the Control Room | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7711 | 7719 | 2 | #2 TURBINE | TURBINE | TURBINE LUBE D.C. PUMP | Provide paralleled electrical control for the DC Lube Oil Pump and “On” and “Off” control for all lube oil pumps in parallel with the local controls in the Control Room. | 2012 | 1 |
| 1296 | 7635 | 7786 | 7953 | 0 | 7719 | 2 | #2 BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | New building heating system | 2015-2020 | 2 |
| 1296 | 7635 | 8093 | 7703 | 0 | 0 | 2 | #2 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Clean and coat AC Water pipes | 2012 | 2 |

Table 13-2 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Overhaul all 4160V switchgear breakers. Use spare breaker elements to overhaul breakers 3,4,5,6,7,8,9,10 off site if necessary. There will be little interruption to plant requirements, recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become "spare" but in good condition. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Replace existing breakers 1, 2 and 12 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Use spare cubicle (UB2-12) for the new U2 Synchronous Condenser Start Pony Motor breaker 12 using a new Eaton Electrical VR-Series type direct replacement for ITE, 4160V, Type 5HK. Consideration should be given to the Eaton Electrical Remote racking device (RPR2), which allows remote racking of a breaker from up to 50ft away, and is programmable for other types of breakers that might be used. One RPR2 would service U1 and U2 needs. | 2013 | 1 |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Change all protection setting to improve arc-flash ratings, unless already completed, including:<br>- Protection settings adjustment on breaker B1, secondary of transformer AT-B.<br>- Replacement of trip unit on breaker B43, Lighting Transformer LT-B feeder. | 2011 | 1 |
| 1296 | 7635 | 8152 | 8156 | 8162 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UNIT SERVICE POWER SYSTEM | POWER CENTRE B | Conduct a complete overhaul to an "as new condition" or replacement of the switchgear, including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. Consider the availability of spare breaker elements to allow a program can be set up to overhaul each breaker off site with essentially no interruption to plant requirements. | 2013 | 1 |
| 1296 | 7635 | 8152 | 8173 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | BATTERY CHARGERS | BATTERY CHARGERS | Replace Unit 2 Battery Chargers 258VDC Panel and breakers | 2013 | 1 |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | Overhaul/upgrade unit to extend the life expectancy to at least 2020 | 2012 | 1 |
| 1296 | 7635 | 8152 | 8174 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | UPS 2, INVERTER | UPS 2, INVERTER | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement | 2012 | 2 |
| 1296 | 7635 | 8152 | 271475 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CABLE RACEWAYS | CABLE RACEWAYS | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271476 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | CONTROL CABLES | CONTROL CABLES | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 7635 | 8152 | 271477 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | POWER CABLES | POWER CABLES | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |

### 13.1.3 Unit 3

**TABLE 13-3 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – UNIT 3**

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8298 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR | Install a rotor flux probe near the turbine end of the stator bore when the rotor is removed in 2016. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8304 | 0 | 3 | U3 GENERATOR | GENERATOR | GENERATOR STATOR | Plan for a rotor rewind by 2020 subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment of performing in 2016. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN. HYDROGEN GAS SYSTEM | Plan for stator rewinding in 2020, subject to findings of 2016 detailed inspection/overhaul. Undertake techno-economic assessment in 2016 with input from operational testing from 2011 onward. | 2016 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 0 | 3 | U3 GENERATOR | GENERATOR | GEN. HYDROGEN GAS SYSTEM | Install a hydrogen consumption “totalizer” in each hydrogen supply line. | 2011 | 1 |
| 1296 | 8193 | 8194 | 8298 | 8313 | 8288 | 3 | U3 GENERATOR | GENERATOR | GENERATOR SEAL OIL SYSTEM | Provide electrical control (both “On” and “Off”) for the AC and DC seal oil pumps in parallel with the local controls in the Control Room | 2011 | 1 |
| 1296 | 8193 | 8194 | 8312 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR EXCITATION SYSTEM | GENERATOR EXCITATION SYSTEM | Replace Unit 3 Static Exciter (also impact the Unit 3 Rectifying Transformer) | 2012 | 1 |
| 1296 | 8193 | 8194 | 8312 | 271680 | 0 | 3 | U3 GENERATOR | EXCITATION TRANSFORMER | EXCITATION TRANSFORMER | Replace Unit 3 Static Exciter Rectifying Transformer | 2012 | 1 |
| 1296 | 8193 | 8194 | 8326 | 0 | 0 | 3 | U3 GENERATOR | GENERATOR SYNCHRONOUS COND | GENERATOR SYNCHRONOUS COND | Modify synchronous condenser - thrust bearing | 2011 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE OIL SYSTEMS | Provide concrete curbing around each unit turbine lube oil tanks and seal oil tanks so as to collect any oil that leaks. Provide Isolation for generator requirements from turbine | 2012 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | BOILER PLANT | TURBINE | TURBINE LUBE OIL SYSTEM | Replace turbine lube Oil conditioners | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8270 | 8275 | 3 | U3 GENERATOR | TURBINE | TURB AC FLUSHING OIL PUMP | Provide paralleled electrical control for the DC Flushing Oil Pump from the Control Room | 2011 | 1 |
| 1296 | 8193 | 8336 | 8503 | 0 | 0 | 3 | BOILER PLANT | BLR AUX STEAM & CONDENSATE | BLR AUX STEAM & CONDENSATE | New building heating system | 2015-2020 | 2 |
| 1296 | 8193 | 8645 | 8262 | 0 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | TURB/GEN WATER COOLING SYS | Clean and coat AC water pipes. | 2012 | 1 |
| 1296 | 8193 | 8645 | 8262 | 9658 | 0 | 3 | UNIT GENERATION SERVICES | TURB/GEN WATER COOLING SYS | T/G COOLING WATER PUMP EAST | Replace Unit 3 AC water pumps and motors. | 2014 | 1 |

### 13.1.4 Common Facilities

TABLE 13-4 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – COMMON

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | Refurbish Unit 3 CW travelling screen | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | Refurbish Unit 3 CW travelling screen | 2012 | 1 |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Include this Switchgear, 4160V/600V relaying in SB2 modernization implementation for the protection relays. | 2012 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Overhaul all 4160V switchgear breakers. Use spare breaker elements a program to overhaul UB3 breakers BFPE3, BFPW3, FDFE3, FDFW3, CEPN3, CEPS3, CWPE3, CWPW3, off site if necessary, with essentially no interruption to plant requirements recognizing that these will be in standby mode from 2015-2020 and as of 2020 will become “spare” but in good condition. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Replace existing UB3 breakers UT3, UAT3, TB3 and SB34 during the complete overhaul with Eaton Electrical VR-Series breakers for a life expectancy to at least 2041. Implement as required Eaton Electrical Remote racking device (RPR2) for remote racking. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271766 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Unit Aux. Board UAB3 and Station Aux. Board SAB34, (600V), manufactured by ITE and installed in 1980. | 2014 | 1 |
| 1296 | 8193 | 8712 | 8704 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | MAIN CONTROLS | MAIN CONTROLS | Upgrade Unit 3 Relay Panels to provide a safe system and redirect the existing field cables to the DCS system including changes to present DCS physical size to accommodate the changes | 2014 | 1 |
| 1296 | 8193 | 8712 | 8751 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | UPS 3 INVERTER | UPS 3 INVERTER | Implement optimization study in conjunction with UPS2, UPS3 and UPS4 replacement | 2012 | 1 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | Replace Unit 3, 129VDC Battery Charger 1 | 2012 | 1 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | Replace Unit 3, 129VDC Battery Charger 2 | 2012 | 1 |
| 1296 | 8193 | 8712 | 8763 | 99038706 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | BATTERY BANKS | BATTERY CHARGER | Replace Unit 3, 258VDC Distribution Panel and breakers | 2012 | 1 |
| 1296 | 8193 | 8712 | 271763 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CABLE RACEWAYS | CABLE RACEWAYS | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 8193 | 8712 | 271764 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | CONTROL CABLES | CONTROL CABLES | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |
| 1296 | 8193 | 8712 | 271765 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | POWER CABLES | POWER CABLES | Install any new cable installations on new tray, and in accordance with the applicable Codes. | 2011 | 1 |

Table 13-4 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 8680 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 AUX. DIESEL GENERATOR | STAGE 2 AUX. DIESEL GENERATOR | Replace Stage II Emergency Diesel, Cummins V-1710-G | 2014 | 1 |
| 1297 | 7199 | 7189 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | Include this relaying in SB12 modernization implementation for the protection relays. | 2014 | 1 |
| 1297 | 7199 | 7189 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | STATION BOARD SB-12 | STATION BOARD SB-12 | Replace existing breakers SSB1, SSB2, SSB3, SSB4 for a life expectancy to at least 2041. Implement, as required, Eaton Electrical Remote racking device (RPR2)remote racking. | 2013 | 1 |
| 1297 | 7199 | 7190 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | DIESEL BUS DB12 | DIESEL BUS DB12 | Diesel Bus DB12 is part of Power Centre "C" and addressed there. | 2013 | 1 |
| 1297 | 7199 | 7192 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Change all Power Centre C (SAB12, Diesel Bus DB12) protection setting to improve arc-flash ratings, | 2013 | 1 |
| 1297 | 7199 | 7192 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | POWER CENTER C | POWER CENTER C | Overhaul to an "as new condition" or replace - including cubicles and breaker elements, extending the life expectancy of the existing switchgear for a further 15-20 years. | 2013 | 1 |
| 1297 | 7199 | 7192 | 7411 | 0 | 0 | 7 | COMMON SYSTEMS | POWER CENTER C | CW PUMPHOUSE MCC C6 | Replace | 2011 | 1 |
| 1297 | 7199 | 7195 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 1 129V D.C. SUPPLY SYSTEM | STAGE 1 129V D.C. SUPPLY SYSTEM | Replace Common, Stage 1, 129VDC Supply System Panel and breakers | 2012 | 1 |
| 1297 | 7199 | 8730 | 8738 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | GENERAL PURPOSE MCC GPB-34 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8740 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | TURB & BLR STANDBY MCC SDB-34 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8742 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | DIESEL BUS DB-34 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8743 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | ESSENTIAL SERVICES MCC ESB-34 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8730 | 8746 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 STATION SERVICE POWER SYSTEM | CW PUMPHOUSE MCC CWP-34 | Refurbish/replace as required | 2015 | 2 |
| 1297 | 7199 | 8771 | 0 | 0 | 0 | 7 | COMMON SYSTEMS | STAGE 2 129V D.C. SUPPLY | STAGE 2 129V D.C. SUPPLY | Replace | 2015 | 2 |
| 1297 | 7199 | 7205 | 7231 | 8918 | 0 | 7 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #2 ATLAS COPCO ROTARY COMP | Replace compressor, subject to the positioning of Holyrood being clarified in 2013 | 2014 | 1 |
| 1297 | 7199 | 7205 | 7231 | 9488 | 0 | 7 | COMMON SYSTEMS | COMPRESSED AIR SYSTEMS | #1 ATLAS COPCO ROTARY COMP | Replace compressor, subject to the positioning of Holyrood being clarified in 2014 | 2015 | 1 |
| 1297 | 7199 | 7206 | 7236 | 0 | 0 | 7 | COMMON SYSTEMS | GAS STORAGE SYSTEMS | HYDROGEN STORAGE AND SUPPLY | Upgrade to Hydrogen storage - LP production & bulk storage | 2012 | 1 |
| 1297 | 7199 | 7251 | 7487 | 0 | 0 | 7 | COMMON SYSTEMS | FIRE PROTECTION SYSTEMS | FIRE PUMPS - DIESEL | Replace fire pump diesel | 2011 | 1 |

Table 13-4 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7283 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Re-paint any corroded steel members in boiler house building to help stop corrosion. Also, repair any leaky pipes to ensure that steel is not exposed to water. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7283 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Prepare and implement roofing replacement and siding upgrade plan in 2012-13 for 2015-2020 | 2015 | 1 |
| 1297 | 7255 | 272255 | 7283 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Modify roof vents hoods | 2011 | 1 |
| 1297 | 7255 | 272255 | 7283 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | MAIN POWERHOUSE | Optimize Warm Air Make Up system. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7283 | 7306 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | BUILDING SERVICES ELEVATOR | Refurbish/replace powerhouse and administration elevators. | 2012-2015 | 2 |
| 1297 | 7199 | 7256 | 271815 | 0 | 0 | 7 | COMMON SYSTEMS | CRANES AND HOISTS | POWERHOUSE CRANE | Replace controls and brakes for auxiliary (and main if necessary) crane | 2011 | 1 |
| 1297 | 7255 | 272255 | 7285 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Re-paint any corroded steel members to prevent further corrosion lost to members. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7285 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | STAGE 1 PUMPHOUSE | Repaint and/or refurbish roofing and siding as required | 2012 | 2 |
| 1297 | 7255 | 272255 | 7286 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Re-paint any corroded steel members to prevent further corrosion lost to members. | 2012 | 2 |
| 1297 | 7255 | 272255 | 7286 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | STAGE 2 PUMPHOUSE | Repaint and/or refurbish roofing and siding as required | 2012 | 2 |
| 1297 | 7255 | 272255 | 7287 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | GUARDHOUSE | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2015 | 3 |
| 1297 | 7255 | 272255 | 7284 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | TRAINING CENTRE | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2013 | 3 |
| 1297 | 7255 | 272255 | 7288 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | H2 & CO2 STORAGE BUILDING | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2013 | 3 |
| 1297 | 7255 | 272255 | 7302 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | SHAWMONT BUILDING | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2012 | 3 |
| 1297 | 7255 | 272255 | 7303 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | MAIN WAREHOUSE | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2013 | 3 |

Table 13-4 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7304 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | WWT PLANT BUILDING | Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2012 | 2 |
| 1297 | 7255 | 272255 | 7305 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Replace/modify WWTP Treatment Basin building. Refurbish/re- paint siding and roofing as required. Fix structural deficiencies (corrosion and cracking and spalling concrete). | 2012 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Improve WWTP basins oil capture and basin escape accesses | 2012 | 1 |
| 1297 | 7255 | 272255 | 7305 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | WWT BASINS BUILDING | Replace/modify WWTP Treatment Basin building | 2012 | 1 |
| 1297 | 7255 | 272255 | 7307 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | Re-paint any corroded steel members | 2011 | 2 |
| 1297 | 7255 | 272255 | 7307 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | Replace stack and affected roof areas | 2011 | 1 |
| 1297 | 7255 | 272255 | 7307 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | Refurbish and re- paint siding and roofing as required. | 2011 | 2 |
| 1297 | 7255 | 272255 | 7307 | 0 | 0 | 8 | BUILDINGS AND SITE | BUILDINGS | GAS TURBINE BUILDING | Replace air intake for marine environment - filter media and/or intake structure | 2011 | 1 |
| 1297 | 9739 | 7203 | 7210 | 0 | 0 | 8 | WATER TREATMENT &ENVIRONMENT | WTP | RAW WATER SYSTEM | Implement new or parallel fresh water line from Quarry Brook Dam. | 2013 | 1 |
| 1297 | 9739 | 10038 | 7263 | 0 | 0 | 8 | WATER TREATMENT &ENVIRONMENT | WWTP | OIL/WATER SEPARATORS | Refurbish oil water separator | 2015 | 1 |

### 13.1.5 Switchyard

**TABLE 13-5 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – SWITCHYARD**

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5990 | 5990 | 310-77-1 | HRDB3B13 | | 10 | HRDTS | BREAKER,B3B13,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5991 | 5991 | 310-77-3 | HRDB12B15 | | 10 | HRDTS | BREAKER,B12B15,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5992 | 5992 | 460-80 AD/2 | HRDB12L18 | | 10 | HRDTS | BREAKER,B12L18,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5993 | 5993 | 310-77-2 | HRDB3L18 | | 10 | HRDTS | BREAKER,B3L18,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5994 | 5994 | 170-73-3 | HRDB1L17 | | 10 | HRDTS | BREAKER,B1L17,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5995 | 5995 | 310-77-4 | HRDB12L42 | | 10 | HRDTS | BREAKER,B12L42,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5996 | 5996 | 188-74-2 | HRDB2B11 | | 10 | HRDTS | BREAKER,B2B11,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5997 | 5997 | 188-74-1 | HRDB1B11 | | 10 | HRDTS | BREAKER,B1B11,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5998 | 5998 | 170-73-2 | HRDB12L17 | | 10 | HRDTS | BREAKER,B12L17,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 5999 | 5999 | 170-73-1 | HRDB2L42 | | 10 | HRDTS | BREAKER,B2L42,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6000 | 6000 | 0464DT72 | HRDB6T10 | | 10 | HRDTS | BREAKER,B6T10,HRD TS | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6001 | 6001 | 0/K3123893 | HRDB12T10 | | 10 | HRDTS | BREAKER,B12T10,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6002 | 6002 | 45510DD/1 | HRDB13B15 | | 10 | HRDTS | BREAKER,B13B15,HRD TS | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6003 | 6003 | 0465DT72 | HRDB7T5 | | 10 | HRDTS | BREAKER,B7T5,HRD TS | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6004 | 6004 | 61130 | HRDB7L2 | | 10 | HRDTS | BREAKER,B7L2,HRD TS | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6005 | 6005 | 63257 | HRDB8L39 | | 10 | HRDTS | BREAKER,B8L39,HRD TS | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6006 | 6006 | 64018 | HRDB6L3 | | 10 | HRDTS | BREAKER,B6L3,HRD TS | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6007 | 6007 | 61131 | HRDB7L38 | | 10 | HRDTS | BREAKER,B7L38,HRD TS | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

Table 13-5 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6008 | 6008 | 991110 | HRDB12L17-1 | | 10 | HRDTS | MODB12L17-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6009 | 6009 | 991110 | HRDB12L42-1 | | 10 | HRDTS | MODB12L42-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6010 | 6010 | 991110 | HRDB2L42-1 | | 10 | HRDTS | MODB2L42-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6011 | 6011 | 991110 | HRDB2B11-1 | | 10 | HRDTS | MODB2B11-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6012 | 6012 | 991110 | HRDB2B11-2 | | 10 | HRDTS | MODB2B11-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6013 | 6013 | 991110 | HRDB12L17-2 | | 10 | HRDTS | MODB12L17-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6014 | 6014 | 991110 | HRDB2L42-2 | | 10 | HRDTS | MODB2L42-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6015 | 6015 | 991110 | HRDB1L17-2 | | 10 | HRDTS | MODB1L17-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6016 | 6016 | 991110 | HRDB12L42-2 | | 10 | HRDTS | MODB12L42-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6017 | 6017 | 991110 | HRDB1L17-1 | | 10 | HRDTS | MODB1L17-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6018 | 6018 | 991110 | HRDB1B11-1 | | 10 | HRDTS | MODB1B11-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6019 | 6019 | 991110 | HRDB12T10-1 | | 10 | HRDTS | MODB12T10-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6020 | 6020 | 991110 | HRDB12L18-1 | | 10 | HRDTS | MODB12L18-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6021 | 6021 | 991110 | HRDB12B15-2 | | 10 | HRDTS | MODB12B15-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6022 | 6022 | 991110 | HRDB13B15-2 | | 10 | HRDTS | MODB13B15-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6023 | 6023 | 991110 | HRDB3L18-2 | | 10 | HRDTS | MODB3L18-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

Table 13-5 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6024 | 6024 | 991110 | HRDB3L18-1 | | 10 | HRDTS | MODB3L18-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6025 | 6025 | 991110 | HRDB3B13-1 | | 10 | HRDTS | MODB3B13-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6026 | 6026 | 991110 | HRDB3B13-2 | | 10 | HRDTS | MODB3B13-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6027 | 6027 | 991110 | HRDB13B15-1 | | 10 | HRDTS | MODB13B15-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6028 | 6028 | 991110 | HRDB12B15-1 | | 10 | HRDTS | MODB12B15-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6029 | 6029 | 991110 | HRDB1B11-2 | | 10 | HRDTS | MODB1B11-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6030 | 6030 | 991110 | HRDB11T5 | | 10 | HRDTS | MODB11T5, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6034 | 6034 | 991110 | HRDB15T6 | | 10 | HRDTS | MODB15T6, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6035 | 6035 | 991110 | HRDB3T3 | | 10 | HRDTS | MODB3T3, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6036 | 6036 | 991110 | HRDB15T8 | | 10 | HRDTS | MODB15T8, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6037 | 6037 | 991110 | HRDB2T2 | | 10 | HRDTS | MODB2T2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6038 | 6038 | 991110 | HRDB1T1 | | 10 | HRDTS | MODB1T1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6039 | 6039 | 991110 | HRDB15T7 | | 10 | HRDTS | MODB15T7, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6053 | 6053 | 991110 | HRDB11B13 | | 10 | HRDTS | MODB11B13, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6546 | 6546 | 991110 | HRDB12L18-2 | | 10 | HRDTS | MODB12L18-2, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 275789 | 275789 | 991110 | HRDB12L42-1 | | 10 | HRDTS | MOD B12L42-1, | 230 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |

Table 13-5 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 6031 | 6031 | 991110 | HRDB8T6 | | 10 | HRDTS | MODB8T6, | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6032 | 6032 | 991110 | HRDB8T7 | | 10 | HRDTS | MODB8T7, | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6033 | 6033 | 991110 | HRDB8T8 | | 10 | HRDTS | MODB8T8, | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6040 | 6040 | 991110 | HRDB8L39-2 | | 10 | HRDTS | Man SwB8L39-2, | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6041 | 6041 | 991110 | HRDB8L39-1 | | 10 | HRDTS | Man SwB8L39-1, | 138 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6042 | 6042 | 991110 | HRDB7T5-2 | | 10 | HRDTS | Man SwB7T5-2, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6043 | 6043 | 991110 | HRDL2L38 | | 10 | HRDTS | Man SwL2L38, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6044 | 6044 | 991110 | HRDB7L38-1 | | 10 | HRDTS | Man SwB7L38-1, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6045 | 6045 | 991110 | HRDB7L38-2 | | 10 | HRDTS | Man SwB7L38-2, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6046 | 6046 | 991110 | HRDB7L2-2 | | 10 | HRDTS | Man SwB7L2-2, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6047 | 6047 | 991110 | HRDB7L2-1 | | 10 | HRDTS | Man SwB7L2-1, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6048 | 6048 | 991110 | HRDB6L3-1 | | 10 | HRDTS | Man SwB6L3-1, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6049 | 6049 | 991110 | HRDB6L3-2 | | 10 | HRDTS | Man SwB6L3-2, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6050 | 6050 | 991110 | HRDB6B7 | | 10 | HRDTS | Man SwB6B7, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6051 | 6051 | 991110 | HRDB7T5-1 | | 10 | HRDTS | Man SwB7T5-1, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 6052 | 6052 | 991110 | HRDB6T10-1 | | 10 | HRDTS | Man SwB6T10-1, | 69 KV | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Section 11.1.1.4. | 2015 to 2035 | 1 |
| 1325 | 991000 | 991100 | 991110 | UAT3 & SAT35 | | 10 | HRDTS | Transformers | UAT3 & SAT35 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5975 | 5975 | 303236 | HRDT1 | | 10 | HRDTS | Transformers | T1 Power | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |

Table 13-5 Cont'd

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1325 | 5976 | 5976 | 61-00-69225 | HRDT2 | | 10 | HRDTS | Transformers | T2 Power | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5977 | 5977 | 287198 | HRDT3 | | 10 | HRDTS | Transformers | T3 Power | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5978 | 5978 | 287199 | HRDT4 | | 10 | HRDTS | Transformers | T4 (spare) | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 3 |
| 1325 | 5979 | 5979 | A-3-S-7520 | HRDT5 | | 10 | HRDTS | Transformers | T5 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5980 | 5980 | 287065 | HRDT6 | | 10 | HRDTS | Transformers | T6 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5981 | 5981 | 287064 | HRDT7 | | 10 | HRDTS | Transformers | T7 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5982 | 5982 | 61-00-68928 | HRDT8 | | 10 | HRDTS | Transformers | T8 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5983 | 5983 | 61-00-69576 | HRDT9 | | 10 | HRDTS | Transformers | T9 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5984 | 5984 | 61-00-69576 | HRDT10 | | 10 | HRDTS | Transformers | T10 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 31297 | 991000 | 991100 | 991110 | UST-1 | | 10 | HRDTS | Transformers | UST-1 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 31297 | 991000 | 991100 | 991110 | ST-2 | | 10 | HRDTS | Transformers | ST-2 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 31297 | 991000 | 991100 | 991110 | UST-3 | | 10 | HRDTS | Transformers | UST-3 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5988 | 5988 | WT-1976-1 | HRDSST-12 | | 10 | HRDTS | Transformers | SST-12 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |
| 1325 | 5989 | 5989 | A-3-S-7608 | HRDSST-34 | | 10 | HRDTS | Transformers | SST-34 | Implement refurbishment/replace per detailed switchyard plan developed in 2012 per Actions in Section 11.1.2.4. | 2015 to 2035 | 1 |

### 13.1.6 Gas Turbine Generator

**TABLE 13-6 SUGGESTED CAPITAL PLAN ITEMS – KEY EQUIPMENT – GAS TURBINE GENERATOR**

| BU# 1 | Asset# 2 | Asset# 3 | Asset# 4 | Asset# 5 | Asset# 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7058 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURB & G/B | Overhaul of power turbine, gearbox | 2011 | 1 |
| 1273 | 7202 | 7308 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON JET ENGINE | Overhaul gas turbine | 2011 | 1 |
| 1273 | 7202 | 7309 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | Refurbish generator | 2015+ | 3 |
| 1273 | 7202 | 7310 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURB ELECT & CONTROL | GAS TURB ELECT & CONTROL | Replace electrical equipment for gas turbine | 2010 | 1 |
| 1273 | 7202 | 7311 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Replace the exhaust stack | 2011 | 1 |
| 1273 | 7202 | 7311 | 0 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AUXILIARY SYSTEMS | Upgrade fuel receipt and feeding and radiator - enclosure | 2012 | 2 |
| 1273 | 7202 | 7311 | 99003602 | 0 | 0 | 5 | GAS TURBINE SYSTEM | GAS TURBINE AUXILIARY SYSTEMS | AIR INLET PLENUM CHAMBER | Replace air inlet plenum/filter media | 2011 | 2 |

## 13.2 Lower Priority Systems Not Required for Synchronous Condensing Operation

### 13.2.1 Unit

TABLE 13-7 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – UNIT 1

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6691 | 6733 | 6780 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER | CONDENSER AIR EXTRACTION | Procure spare vacuum pump and motor for Units 1 & 2 (and 3 as practical) | 2012 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8876 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER | CONDENSER VACUUM PUMP NORTH | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 6690 | 6691 | 6733 | 6780 | 8877 | 1 | #1 TURBINE & GENERATOR | TURBINE CONDENSER | CONDENSER VACUUM PUMP SOUTH | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 6690 | 6691 | 271309 | 6777 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Replace the steam seal regulator | 2011 | 1 |
| 1296 | 6690 | 6691 | 271309 | 6779 | 0 | 1 | #1 TURBINE & GENERATOR | TURBINE | TURBINE TURNING GEAR | Refurbish chain and mechanism | 2011 | 2 |
| 1296 | 6690 | 6699 | 0 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER PLANT | BOILER PLANT | Install nitrogen blanketing. No other pending Level 2 or next inspection | 2013 | 2 |
| 1296 | 6690 | 6699 | 6702 | 6878 | 0 | 1 | #1 BOILER PLANT | BLR SUPERHEAT& REHEAT ASS'Y | BOILER REHEATER | Implement addition of RH surface to match design temps and efficiency, subject to decision on Holyrood | 2012 | 2 |
| 1296 | 6690 | 6699 | 6701 | 6701 | 0 | 1 | #1 BOILER PLANT | BOILER F.W. & SAT'D STEAM | BOILER BLOWDOWN TANK | Replace tank | 2011 | 1 |
| 1296 | 6690 | 6699 | 6703 | 0 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | Upgrade air ducts to reduce vibration, improve efficiency | 2012 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 0 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | Assess fluid coupling/VFD for BFWP and FDF | 2011 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6943 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Install vibration monitoring | 2012 | 2 |
| 1296 | 6690 | 6699 | 6703 | 8777 | 6944 | 1 | #1 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Install vibration monitoring | 2012 | 2 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | Assess economic aspects of Intelligent Sootblowing | 2011 | 3 |
| 1296 | 6690 | 6699 | 6704 | 6920 | 0 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | FD fan ductwork modifications | 2011 | 3 |
| 1296 | 6690 | 6699 | 6704 | 6919 | 270294 | 1 | #1 BOILER PLANT | BOILER GAS SYSTEM | BOILER STACK BREECHING | Refurbish stack breeching | 2011 | 1 |
| 1296 | 6690 | 6709 | 8799 | 7045 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION | COND EXTRACTION PUMP NORTH | Replace as required per current inspection and overhaul findings | 2013 | 3 |
| 1296 | 6690 | 6709 | 8799 | 7049 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | CONDENSATE EXTRACTION | COND EXTRACTION PUMP SOUTH | Replace as required per current inspection and overhaul findings | 2013 | 3 |

Table 13-7 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8835 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Install vibration monitoring | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 2 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 6690 | 6709 | 6712 | 8836 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Install vibration monitoring | 2012 | 1 |
| 1296 | 6690 | 6709 | 6713 | 7113 | 0 | 1 | #1 CONDENSATE & F.W. SYSTEM | HIGH PRESSURE FEEDWATER SYS | H.P. HEATER 5 | Replace HP #5 Heater | 2013 | 1 |
| 1296 | 6690 | 6715 | 6782 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURB/GEN COOLING SYSTEM | TURB/GEN COOLING SYSTEM | Clean and coat AC Water pipes | 2012 | 2 |
| 1296 | 6690 | 6715 | 270182 | 7146 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 6690 | 6715 | 270182 | 7147 | 0 | 1 | #1 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 6690 | 6723 | 6721 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | RELAY RM PROTECTION & CONTROL | RELAY RM PROTECTION & CONTROL | Implement modernization study re: appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. | 2014 | 1 |
| 1296 | 6690 | 6723 | 6722 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | MAIN CONTROLS | MAIN CONTROLS | Implement study to migrate Governor System and Burner Management to DCS | 2014 | 2 |
| 1296 | 6690 | 6723 | 6693 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | Assess and implement GE migration of the Mark V to the Mark Ve system. | 2013 | 1 |
| 1296 | 6690 | 6723 | 6693 | 333928 | 0 | 1 | #1 UNIT GENERATION SERVICES | TURBINE GOVERNOR SYSTEM | Holyrood Mark V Auto Sync | No Capital | | |
| 1296 | 6690 | 6723 | 6693 | 99000260 | 0 | 1 | #1 UNIT GENERATION SERVICES | #1 UNIT GENERATION SERVICES | INSTALL GOVENOR UNIT 1 - MFG C | No Capital | | |
| 1296 | 6690 | 6723 | 7173 | 0 | 0 | 1 | #1 UNIT GENERATION SERVICES | BURNER MANAGEMENT | BURNER MANAGEMENT | Transfer Burner Management system from PLC system to DCS. Replace any existing field mounted pressure switches by analog transducers. Flame Scanners remain unchanged. | 2011 | 1 |

### 13.2.2 Unit 2

**TABLE 13-8 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – UNIT 2**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7636 | 7664 | 7694 | 8884 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P NORTH | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 7635 | 7636 | 7664 | 7694 | 8891 | 2 | #2 TURBINE CONDENSER SYSTEM | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC P/P SOUTH | Refurbish/Replace vacuum pumps and motors as required. | 2012 | 2 |
| 1296 | 7635 | 7636 | 271317 | 7686 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE GLAND STEAM SYSTEM | Replace the steam seal regulator | 2012 | 1 |
| 1296 | 7635 | 7636 | 271317 | 7692 | 0 | 2 | #2 TURBINE | TURBINE | TURBINE TURNING GEAR | Refurbish chain and mechanism | 2014 | 1 |
| 1296 | 7635 | 7786 | 0 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER PLANT | BOILER PLANT | Install nitrogen blanketing. No other pending Level 2 or next inspection | 2013 | 2 |
| 1296 | 7635 | 7786 | 7789 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER FW & SAT'D STEAM SYS | None , pending Level 2 or next inspection | | |
| 1296 | 7635 | 7786 | 7810 | 7835 | 0 | 2 | #2 BOILER PLANT | BOILER SUPERHEATER & REHEAT | BOILER REHEATER | Implement addition of RH surface to match design temperatures and efficiency, subject to economic assessment. | 2014 | 2 |
| 1296 | 7635 | 7786 | 7789 | 7789 | 0 | 2 | #2 BOILER PLANT | BOILER FW & SAT'D STEAM SYS | BOILER BLOWDOWN TANK | Replace tank | 2011 | 1 |
| 1296 | 7635 | 7786 | 7838 | 0 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | Upgrade air ducts to reduce vibration, improve efficiency | 2014 | 1 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 0 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN ASSEMBLY | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7843 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Install vibration monitoring | 2012 | 2 |
| 1296 | 7635 | 7786 | 7838 | 8781 | 7844 | 2 | #2 BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Install vibration monitoring | 2012 | 2 |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | Assess economic aspects of Intelligent Sootblowing | 2011 | 3 |
| 1296 | 7635 | 7786 | 7890 | 7904 | 0 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | FD fan ductwork modifications | 2011 | 3 |
| 1296 | 7635 | 7786 | 7890 | 7900 | 271327 | 2 | #2 BOILER PLANT | BOILER GAS SYSTEM | STACK BREECHING | Refurbish stack breeching | 2012 | 1 |
| 1296 | 7635 | 7978 | 8800 | 7986 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | COND EXTRACTION PUMP NORTH | Replace as required per current inspection and overhaul findings | 2013 | 3 |
| 1296 | 7635 | 7978 | 8800 | 7987 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | COND. EXTRACTION PUMP SOUTH | Replace as required per current inspection and overhaul findings | 2013 | 3 |

Table 13-8 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 3 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8847 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP WEST | Install vibration monitoring | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 3 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 7635 | 7978 | 8037 | 8848 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP EAST | Install vibration monitoring | 2012 | 1 |
| 1296 | 7635 | 7978 | 8059 | 8067 | 0 | 2 | #2 CONDENSATE & F.W. SYSTEM | H.P. FEEDWATER SYSTEM | H.P. HEATER 5 | Replace HP Htr 5 - similar to Unit 1. | 2013 | 1 |
| 1296 | 7635 | 8093 | 271486 | 8106 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 7635 | 8093 | 271486 | 8107 | 0 | 2 | #2 UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 7635 | 8152 | 271478 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | SWITCHGEAR 4160 & 600 VOLT | SWITCHGEAR 4160 & 600 VOLT | Implement changes to this Switchgear 4160V/600V relaying in UB2 modernization study (5.3.2.15 IV) for the protection relays. Consider that the remaining P&B Golds relays remain and not be replaced by Schweitzer 701 MPR's. As of 2015 the breakers utilizing these will become standby and as of 2020 will become spare. | 2013 | 1 |
| 1296 | 7635 | 8152 | 271479 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TSI | TSI | Implement Turbine Supervisory System replacement | 2013 | 1 |
| 1296 | 7635 | 8152 | 7677 | 0 | 0 | 2 | #2 ELECTRICAL & CONTROLS SYS | TURBINE GOVERNOR SYSTEM | TURBINE GOVERNOR SYSTEM | Assess and implement GE migration of the Mark V to the Mark Ve system. Replace existing 196 processor and modernize operator and maintenance stations. Field wiring and devices remain the same. | 2013 | 1 |

### 13.2.3 Unit 3

**TABLE 13-9 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – UNIT 3**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8194 | 8223 | 8252 | 8892 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP NORTH | CONDENSER AIR VAC PUMP NORTH | Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room | 2015 | 1 |
| 1296 | 8193 | 8194 | 8223 | 8252 | 8893 | 3 | TURBINE CONDENSER SYSTEM | CONDENSER AIR VAC PUMP NORTH | CONDENSER AIR VAC PUMP SOUTH | Refurbish/replace vacuum pumps and motors as required. Provide electrical control (both “On” and “Off”) for the vacuum pumps in parallel with the local controls in the Control Room | 2015 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GOVERNOR SYSTEM | Upgrade the mechanical fly-ball type Turbine Governor System to As-Built condition or be replaced using electronic controls.. | 2013 | 1 |
| 1296 | 8193 | 8194 | 271675 | 8236 | 99024410 | 3 | U3 GENERATOR | TURBINE | BENTLEY NEVADA TURBINE SUPERVI | Implement replacement option | 2013 | 2 |
| 1296 | 8193 | 8194 | 271675 | 8244 | 0 | 3 | U3 GENERATOR | TURBINE | TURBINE GLAND STEAM SYSTEM | Replace steam seal regulator | 2013 | 1 |
| 1296 | 8193 | 8336 | 0 | 0 | 0 | 3 | BOILER PLANT | BOILER PLANT | BOILER PLANT | Install nitrogen blanketing. No other pending Level 2 or next inspection | 2013 | 2 |
| 1296 | 8193 | 8336 | 8339 | 8339 | 0 | 3 | BOILER PLANT | BLR FW & SAT STM | BOILER BLOWDOWN TANKS | Replace blowdown tank | 2011 | 1 |
| 1296 | 8193 | 8336 | 8387 | 0 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER AIR SYSTEM | Upgrade air ducts to reduce vibration, improve efficiency | 2013 | 1 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 0 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN SYSTEM | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8392 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN EAST | Install vibration monitoring | 2012 | 2 |
| 1296 | 8193 | 8336 | 8387 | 8782 | 8393 | 3 | BOILER PLANT | BOILER AIR SYSTEM | BOILER F.D. FAN WEST | Install vibration monitoring | 2012 | 2 |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | Assess economic aspects of Intelligent Sootblowing | 2012 | 3 |
| 1296 | 8193 | 8336 | 8437 | 8452 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER GAS SYSTEM | BOILER SOOTBLOWING SYSTEM | FD fan ductwork modifications | 2012 | 3 |
| 1296 | 8193 | 8336 | 8437 | 8448 | 271682 | 3 | CONDENSATE & F.W. SYSTEM | BOILER GAS SYSTEM | STACK BREECHING | Refurbish stack breeching | 2013 | 1 |
| 1296 | 8193 | 8528 | 8801 | 8536 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSER EXTRACTION P/P NORTH | CONDENS EXTRACTION P/P NORTH | Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatible with all units. | 2014 | 3 |
| 1296 | 8193 | 8528 | 8801 | 8537 | 0 | 3 | CONDENSATE & F.W. SYSTEM | CONDENSER EXTRACTION P/P SOUTH | CONDENS EXTRACTION P/P SOUTH | Refurbish and replace as required per next inspection and overhaul findings. Procure spare motor compatible with all units. | 2014 | 3 |

Table 13-9 Cont'd

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8859 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - EAST | Install vibration monitoring | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | CONDENSATE & F.W. SYSTEM | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | Retrofit of variable speed control – fluid couplings or variable speed drives to reduce energy consumption and improve efficiency | 2013 | 2 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | UNIT GENERATION SERVICES | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | Procure a spare 4 kV motor, to allow rewind of Units 1 and 2 and if practical Unit 3 motors as required | 2012 | 1 |
| 1296 | 8193 | 8528 | 8590 | 8860 | 0 | 3 | UNIT GENERATION SERVICES | BOILER FEEDWATER PUMPING | BOILER FEED PUMP - WEST | Install vibration monitoring | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8658 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP EAST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8659 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW PUMP WEST | Procure spare motor - common to Units 1 & 2; adaptable Unit 3 to extent practical | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8649 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS EAST | Refurbish Unit 3 CW travelling screen | 2012 | 1 |
| 1296 | 8193 | 8645 | 271678 | 8650 | 0 | 3 | UNIT GENERATION SERVICES | CW SYSTEM | CW TRAVELLING SCREENS WEST | Refurbish Unit 3 CW travelling screen | 2012 | 1 |
| 1296 | 8193 | 8712 | 8698 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | RELAY RM P&C | RELAY RM P&C | Implement modernization study refurbishing the old GE electro-magnetic relays or new multi-function relaying. | 2014 | 1 |
| 1296 | 8193 | 8712 | 271767 | 0 | 0 | 3 | ELECTRICAL SYSTEM & CONTROL | TSI | TSI | Replace with selected preferred option | 2013 | 1 |

### 13.2.4 Common Facilities

TABLE 13-10 SUGGESTED CAPITAL PLAN ITEMS – LOWER PRIORITY – COMMON

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset # 5 | Asset # 6 | Unit | Asset 2/3 | Asset 3/4 | Description | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7199 | 7204 | 7223 | 0 | 0 | 7 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | *HEAVY OIL TRANSFER TO STORAGE | Replace electric heat trace system | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7441 | 0 | 7 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #1 TANK | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2012 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7443 | 0 | 7 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #3 TANK | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2011 | 1 |
| 1297 | 7199 | 7204 | 7224 | 7444 | 0 | 7 | COMMON SYSTEMS | HEAVY OIL & FUEL ADDITIVE | HEAVY OIL - #4 TANK | Complete recommended actions from SGE Acres report - replace tank bottom and apply protective coating to new bottom and 1 meter of shell. Complete API653 inspection. | 2010 | 1 |
| 1297 | 9739 | 7203 | 286053 | 6967 | 0 | 8 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | Replace alarm annunciation panels | 2011 | 2 |
| 1297 | 9739 | 7203 | 286053 | 6967 | 0 | 8 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #1 CONDENSATE POLISHER PLANT | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8127 | 0 | 8 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | Replace alarm annunciation panels | 2011 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8127 | 0 | 8 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #2 CONDENSATE POLISHER PLANT | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 2 |
| 1297 | 9739 | 7203 | 286053 | 8686 | 0 | 8 | WATER TREATMENT & ENVIRONMENT | WATER TREATMENT PLANT | #3 CONDENSATE POLISHER PLANT | Replace control operating panels, subject to decision on generation continues to 2020+. | 2014 | 1 |

### 13.2.5 Switchyard

None apply.

### 13.2.6 Gas Turbine Generator

None apply.

# 14 CONCLUSIONS

The following major conclusions are based on the review of the condition assessment documentation in Sections 8 to 12 of this report. They are intended to highlight the key issues at a summary level.

## 14.1 Overall and Station Wide

1. Holyrood's overall condition is very good. Units 1, 2, and 3 are approximately 41, 40, and 31 years of age respectively. The units' operational ages for the majority of equipment and systems are actually 20, 19, and 16 years respectively, or even less when the typical operating load range of between 70 and 140 MW is considered.

2. Holyrood can, with modest additional refurbishment/investment, be expected to continue to provide reliable electricity generation service to the generation end dates of either 2015 or 2020.

3. Holyrood can, when its units are converted to synchronous condensing operation in or about 2014/2015, with additional life extension investment in the electrical portion of the facility, be expected to make an end date for synchronous condensing of 2041.

4. The Level 2 condition assessments identified in Chapters 8 to 11 and summarized in Chapter 12 are necessary to more accurately assess the ability of the identified systems to meet their respective remaining life requirements. The identified priorities may be useful in assigning funding.

5. The steam turbines are generally considered to be in good condition, with some specific issues identified in Chapters 8 to 10. Their condition supports an inspection/overhaul interval of 9 years supplemented with minor 3 year valve outages, subject to any unexpected changes in conditions found at each outage and in particular their next inspection/overhaul.

6. The generators are generally considered to be in moderately poor condition, particularly Units 1 and 2. Their specifics and suggested actions are identified in Chapters 8 to 10. The condition of all three generators, as well as industry experience and their importance for synchronous condensing to 2041, are not conducive with a nine year generator inspection interval. A six year cycle is more representative of their current condition.

7. The generator operating and monitoring conditions identified in Chapters 8 to 10, particularly those associated with hydrogen conditions and generator monitoring require review and action.

8. Detailed condition assessments of high pressure and temperature feedwater and steam lines, primarily main steam and hot reheat steam lines, on all units have not been carried out for some time and should be considered a very high priority safety and reliability due diligence task.

9. Some of Holyrood's large high pressure and temperature pipe hangers have not been checked and adjusted in some time. The hanger monitoring program appears to have been largely inactive in the last few years.

10. Steam side components of Holyrood's boilers are considered to have considerable remaining life, beyond that required to meet a 2020 end of generation service. A Level 2 condition assessment is necessary for the highest temperature and pressure headers identified in Chapters 8 to 10, as well as those parts not having the necessary inspection and condition assessment data to confirm their remaining life.

11. Holyrood's high pressure feedwater heat exchangers have not been extensively tested, although they are checked and leak tested every year. Those that have been replaced once are considered to have considerable remaining life, enough to meet a 2020 end of generation service. The necessary Level 1 data is not sufficient to confirm this. Level 2 testing, albeit at a lower priority level, is technically warranted based on the process.

12. Holyrood's deaerators are considered to have considerable remaining life, enough to meet a 2020 end of generation service. Inspections are done during the annual boiler inspection and maintenance work. Despite this, however, some internal parts do not have the necessary inspection and condition assessment data to confirm this and require some Level 2 work.

13. Holyrood's low pressure feedwater heat exchangers appear to be original equipment and have not been tested beyond annual leak testing. It is likely that most are capable of meeting the 2020 end of generation service. The necessary Level 1 data is not sufficient to confirm this.

14. Holyrood's programs for major equipment, pumps, and motor inspection scheduling, and overall PM process seem reasonable and effective.

15. Holyrood's large 4 kV motors (boiler feedwater pumps, forced draft fans, condensate extraction pumps, and cooling water pumps) are at the stage in their physical/operating lives where reliability becomes an issue. Existing test data does not suggest an imminent issue. No spares currently exist for these long lead purchase items that would minimize outage duration and are considered to be warranted to maintain high availability.

16. Much of the plant switchgear (all units and common facilities), primarily many breakers and motor control centres, has reached a physical age where extensive replacements over the next three to ten years will be critical for plant reliability. An optimization program involving significant new purchases and sparing is required to balance costs and priorities in light of the plant's role going forward.

17. Condensate polisher annunciator and control panels on all units, with the exception of the new Unit 3 annunciator, are considered obsolete and in need of replacement. No information on the condition of any of the condensate polishers was identified.

18. The control room, while functional, is dated and a mixture of various technologies. A study of the appropriate modifications and upgrades to improve its efficiency and effectiveness is warranted.

## 14.2 Site Conditions

1. The site is in generally in good condition, especially with the rehabilitation of the main oil tank farm spill retention berms.

2. The plant access road is in very poor condition and needs repair to reduce probability of future accident. On site roads are in fair condition, likely to require replacement/refurbishment over next five years.

3. The on-site landfill is nearing end of life and requires management as well as expansion or replacement.

## 14.3 Common Facilities

1. The electrically heat traced heavy fuel oil transfer pipe from the fuel off loading dock to main storage tanks has failed in the past and the temporary fix cannot be expected to sustain operation for long term. It is a reliability issue and needs to be replaced immediately to avoid having a major impact on plant operations.

2. The heavy oil day tank does not appear to have been internally inspected since its installation in the late 1980's and should be internally inspected.

3. The transformers have all reached physical and operational ages where reliability degradation and susceptibility to failure (particularly as a result of potential system upsets) are significant concerns. These units are typically long lead replacement or repair items. There is some existing sparing and configurational sparing currently in place. Refurbishment and condition monitoring is undertaken on a regular basis, but condition monitoring should be more frequent and extensive.

4. Circulating water intake and discharge structures and large concrete pipes from the pumphouses to the condensers and to the discharge siphon pits have not been inspected for some time and should be inspected in near future.

5. The condition of underground services (raw water, fire water, grounding, waste water piping, and lighting) was identified as uncertain. Development of an appropriate assessment and/or monitoring program is desirable, although not a detailed Level 2 assessment in most cases.

6. Some older systems are single contingency failure candidates, having no current contingency option. Their condition needs to be assessed and monitored. These include the dam at Quarry Brook, the raw water supply line from the damsite to the Stage 1 pumphouse, the original water treatment plant clarifier, sandfilters, and clearwell. Inspections and any resulting work to mitigate unplanned (not necessarily long) shutdowns during critical periods are warranted.

7. In the period from 2015 through 2025, the powerhouse and pumphouse roofs will be reaching end of life due to aging. Some minor leaks are occurring now. A plan to effectively mitigate equipment damage from roof leaks will be required.

8. Some environmental systems and equipment are inconsistent with current or anticipated short term requirements. They need to be inspected and/or considered for refurbishment or replacement to bring them up to current and expected performance levels. These may include new CEM systems, improvements to waste water basin discharge treatments, oil filled exciter transformer replacement due to PCB levels (when and if new PCB regulations are implemented), and oily water separator and pipes.

9. A new building heating system (auxiliary boiler/steam or electric) will be needed after 2015 when the plant unit boilers may not be operating during winter peak periods. Some existing steam fed unit heaters and piping systems also appear to be in poor condition and likely need replacement.

10. The powerhouse elevator and the administration building elevator will be required up to 2041. The powerhouse elevator is expected to need extensive refurbishment/replacement in the 2012 to 2015 period.

11. The waste water basin building needs repair and modification or replacement to better address current corrosion, safe egress, and ventilation needs.

12. The diesel fire water pump is at end of life and requires replacement. The capacity requirement of the new fire protection system is higher than in the past due to recent expansion. The new pump, and possibly a new electric pump, needs to be capable of handling the additional requirement.

13. The Stage 2 diesel is original equipment at the end of life and needs to be replaced.

14. The Stage 1 air compressors are near end of life and need to be replaced in the next few years.

## 14.4 Unit 1

1. The generator stator winding is in poor condition. Its next overhaul is in 2012. It has a significant likelihood of encountering issues prior to 2021 when its next overhaul would currently be scheduled. Given an end date of 2041, a rewind in 2012 is recommended. A later date is likely to result in reliability degradation and higher potential for failure.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2012 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

## 14.5 Unit 2

1. The generator stator winding is in poor condition. Its next overhaul is in 2014. It has a significant likelihood of encountering issues prior to 2023 when its next overhaul would currently be scheduled. Given an end date of 2041, a stator rewind in 2014 is recommended, subject to findings in 2012 on Unit 1.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, stud bolt issues, and turning gear issues. These should be examined further and/or addressed at the next 2014 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

There are also options for improving the efficiency of the facility in the short term such as:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency; and

b) Repairing previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs

## 14.6 Unit 3

1. The generator is in reasonable condition. Its next overhaul is in 2016. Nevertheless, it has a significant likelihood of encountering rotor winding issues prior to its next currently scheduled outage in 2025. Given an end date of 2041, a rotor rewind may be warranted in 2016 or earlier than 2025.

2. The steam turbine is in generally good condition and is expected to make the 2020 generation end date. It continues to have main and intercept valve issues, as well as stud bolt issues. Its mechanical governor system also experiences some control issues. These should be examined further and/or addressed at the next 2016 major overhaul.

3. The boiler is generally in good shape, especially with the change in fuels. Some legacy effects of history of high sulphur, high vanadium oil use is likely to continue – tube leaks and thinness. Others such as economizer plugging, air preheater corrosion and plugging are expected to continue to diminish.

4. The stack breeching requires an upgrade or replacement. The steel casing and support structure has localized corrosion and the internal insulating liner has significant deterioration.

5. The Unit 3 control room relay panels cannot accommodate the current and required wiring and need to be replaced for safety reasons.

6. When decoupled from the turbine, Unit 3 generator has no thrust bearing to address lateral movement during synchronous condensing operation and requires modification to reduce long term vibration and damage.

7. Unit 3 Exciter is considered at end of life and the entire system should be replaced.

## 14.7 Black Start Gas Turbine

1. The black start gas turbine is 42 years old, but with few operating hours and several thousand starts and stops.

2. The unit is experiencing significant reliability (starts/stops, operation) and safety problems.

3. The gearbox has been a source of oil leaks and fires, likely a seal issue that has existed for some time. As a result, recent fires have limited the unit's use.

4. The power turbine, gas turbine, gearbox, and generator are overdue for a major inspection/overhaul, based on recent boroscope and on-site power turbine inspections and industry practice.

5. The stack is badly corroded and appears to be leaking water into the back end of the gas turbine.

6. The intake has corrosion at the base and appears to have contributed to front end corrosion of the gas turbine, possibly an issue with the current filter media.

7. The fuel receiving system and lube oil cooler are outdoors and are badly corroded.

## 14.8 Switchyard

1. The transformers have all reached a physical and operational age where reliability degradation and susceptibility to failure (particularly as a result of potential system upsets) are significant concerns. These units are typically long lead item replacements. There is some existing sparing and configurational sparing (essentially parallel or potentially parallel systems). Refurbishment and condition monitoring is undertaken on a regular basis, but condition monitoring should be more frequent and extensive.

2. Most switchyard switchgear, primarily motor operated breakers, is at physical ages where extensive refurbishment and/or replacement over the next five to ten years will be necessary for station reliability. Hydro has a switchyard inspection program and continuously repairs and modifies breakers and switches as required. Development and implementation of an optimization program which would also include other important switchyard equipment such as potential transformers (PT's) and current transformers(CT's) involving significant new purchases, refurbishing, and sparing to balance costs and priorities in light of the station's role going forward is desirable.

## 14.9 Facility Management

1. Overall facility management is excellent, and demonstrates a practice of continuous improvement. It is evident that Holyrood staff and management have worked hard to maintain high standards of operation and maintenance and safety, while recognizing economic factors.

2. Existing document management systems and implementation at the plant are difficult to work with, particularly by external contractors. Many records are only available from specific individuals.

3. Technical staffing is good, but some additions to on-site operations engineering support are likely warranted in the area of civil engineering. Succession planning in critical technical and operation areas is underway, but remains a key issue throughout the industry.

4. Operator training for situations not currently standard is needed, such as procedures for more frequent starting and stopping, lower load operation, and addressing critical generator indicators. A simulator may be warranted for training given the long periods of non-operation.

# 15 RECOMMENDATIONS

## 15.1 Overall and Station Wide

1. Implement the recommended Level 1 and 2 condition assessment tasks identified in Chapters 8 to 11 and summarized in Chapter 12, including augmented steam turbine and generator overhauls at their next normal overhaul date to the extent economically practical.

2. Retain the 9 year major inspection/overhaul interval and minor 3 year valve outage timing for the steam turbines, subject to any unexpected changes in conditions found at their inspection/overhauls and, in particular, at their next inspection/overhaul. Undertake the steam turbine pre-outage actions identified in Chapters 8 to 10.

3. Modify the generator inspection and overhaul interval back to every six years. Address the specific actions identified in Chapters 8 to 10, in particular those permitting better performance baselining in the balance of 2010 and 2011.

4. Perform in 2011 limited generator testing, with rotor in and on all units but particularly on Unit 1, to the extent safe and economically practical to obtain baseline data. Undertake work needed to scope out the details of the inspection/testing and stator rewind during the 2012 Unit 1 outage.

5. In 2011 and 2012, carry out a detailed condition assessment of high pressure and temperature feedwater and steam lines on all units as a very high priority safety and reliability due diligence task. Plan and implement an extensive high pressure and temperature pipe hanger inspection program as part of the plant's PM, safety, and reliability due diligence programs.

6. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on boiler components identified in Chapters 8 to 10.

7. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on high pressure heater components identified in Chapters 8 to 10.

8. Carry out Level 2 inspections and testing in 2012, 2013, and 2014 for Units 1, 2, and 3 respectively on deaerator components identified in Chapters 8 to 10.

9. Carry out Level 2 inspections and testing on low pressure heaters in 2011 for Units 1, 2, and 3.

10. Maintain existing programs for major equipment, pumps, and motor inspection scheduling and overall PM process.

11. Procure one spare 4 kV motor for each of the boiler feedwater pumps, the forced draft fans, condensate extraction pumps, and the cooling water pumps – primarily designed for Units 1 and 2, but with plans on how to use them with Unit 3 as necessary.

12. Develop and implement an optimized plan for station switchgear (all units, common facilities), primarily breakers and motor control centres, addressing a combination of extensive replacement and sparing to maintain station reliability without interrupting normal unit operation.

13. Inspect all condensate polishers in 2011. Replace Units 1 and 2 remaining enunciator panels (Unit 3 enunciator panel was replaced in 2007). Assess the cost-benefit of replacing polisher control panels on all units considered obsolete in light of generation end of service timeline.

## 15.2 Site Conditions

1. Negotiate to have the plant access road repaired to reduce probability of future accident.

2. Develop an onsite road replacement/refurbishment plan in 2011 addressing issues over next five years.

3. Close and manage existing on-site landfill in parallel with opening of a new on-site facility or expansion of the current one.

## 15.3 Common Facilities

1. Replace the electric heat tracing for the heavy fuel oil transfer pipe line from the off loading dock to the main storage tanks in 2010 or early 2011.

2. Internally inspect the heavy oil day tank in 2011 for regulatory purposes.

3. Perform transformer oil gas analyses in 2010 and 2011 and complete the Hydro transformer electrical testing as per the schedule in Chapter 11.

4. Perform underwater inspections on circulating water intake and discharge structures and piping in 2011. Perform walk down or remote integrity inspections of the large concrete pipes from the pump houses to the condensers and to the discharge siphon pits and inspect the stop log structure in 2011.

5. Develop a program to assess the condition of underground services (raw water, fire water, grounding, waste water piping, and lighting) as the current condition is not clear.

6. Undertake Level 2 integrity inspections of single contingency failure candidates including the dam at Quarry Brook, the raw water supply line from the dam site to the Stage 1 pumphouse, and the original water treatment plant clarifier, sand filters, and clearwell.

7. Develop a powerhouse and pumphouse roof replacement plan.

8. Improve, refurbish or replace CEM systems, waste water basin discharge treatment systems, oil filled exciter transformers (if and when new PCB regulations are implemented), and the oily water separator and pipes.

9. Develop a plan for a new building heating system (auxiliary boiler/steam or electric) needed after 2015. Assess and replace existing steam fed unit heaters and piping systems that are in poor condition.

10. Refurbish or replace the existing powerhouse elevator in the 2012 to 2015 period, and assess the timing requirements for a new administration building elevator.

11. Repair the waste water basin building to address current corrosion, safe egress, and ventilation needs in 2012.

12. Replace in 2011 the diesel fire pump, which is at end of life, in order to match the capacity requirements of the new fire protection system. Replace the electric firewater pump if capacity is less than the new requirement.

13. Replace the Stage 2 diesel generator in or about 2014.

14. Replace the Stage 1 air compressors that are near their end of life in 2014 and 2015.

## 15.4 Unit 1

1. Undertake a generator stator rewind as part of the 2012 generator overhaul. Initiate planning early in 2011. Undertake the generator actions list in 2010 and 2011.

2. Address issues and action with steam turbine, including wok on main and intercept valve issues, stud bolt issues, and turning gear issues as per sections 8, 9, and 10 of this report.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

## 15.5 Unit 2

1. Undertake a generator stator rewind as part of 2014 generator overhaul. Initiate pre-work early in 2013. Undertake early generator actions list in 2011.

2. Address issues and actions with steam turbine, including work on main and intercept valve issues, stud bolt issues, and turning gear issues.

3. Refurbish stack breeching per current plans.

Where economically feasible, assess and implement those efficiency improvement options for the facility which have short term economic benefits, e.g.:

a) Addition of reheat boiler tubes to improve reheat steam conditions and cycle efficiency.

b) Repair of previously damaged (but not fully repaired) steam turbine elements or upgrading existing elements with more efficient designs.

## 15.6 Unit 3

1. Undertake a generator rotor rewind at the next generator overhaul in 2016 or, with some additional reliability risk, between 2020 and 2022 subject to the findings of the 2016 inspection.

2. Address issues and actions with the steam turbine, including work on main and intercept valve issues, and stud bolt issues.

3. Assess the cost-benefit of replacing the existing steam turbine mechanical governor system in 2011 for implementation during the 2013 minor valve outage.

4. Refurbish stack breeching per current plans.

5. For safety reasons, replace the Unit 3 control room relay panels as soon as practical to accommodate the current and required wiring.

6. Implement Unit 3 generator thrust bearing retrofit to address lateral movement during synchronous generator operation to eliminate long term vibration and damage.

## 15.7 Black Start Gas Turbine

1. In 2010 inspect/assess the power turbine, gas turbine, gearbox, and generator without removing the unit to confirm major inspection/overhaul requirement.

2. Complete 2010 boroscope inspections on gas and power turbine, combustor, and gearbox.

3. Inspect and assess in 2010 the air intake and exhaust stack structure.

4. Undertake in 2010 off-site overhaul of power turbine and gas turbine, and on-site or off-site gear-box inspection and gearbox seal replacement.

5. Undertake in 2011 detailed inspection/testing of generator and electrical auxiliaries.

6. Develop a design and implement the replacement the fuel handling and lube oil coolers inside an enclosure.

7. Assess in 2010 the alternative of replacing the black start generator with a new or refurbished unit.

## 15.8 Switchyard

1. Implement identified Level 2 transformer gas in oil testing in 2010 and 2011. Catch up on backlogged electrical testing using full Hydro test protocol and report during these and future regularly scheduled electrical testing periods.

2. Considering the requirements going forward, assess the cost-benefit of additional transformer equipment sparing and configurational sparing possibilities. Undertake more frequent and complete Hydro condition monitoring.

3. Maintaining station reliability without interrupting normal unit operation, develop and implement an optimized plan for switchyard equipment such as switchgear (primarily older breakers) as well as other components such as potential transformers (PT's) and current transformers (CT's), addressing a combination of extensive refurbishment and/or replacement and sparing.

## 15.9 Management

1. Upgrade the existing document management procedures, systems, and resources at the plant

2. Implement current station staffing plan, including some moderate additions in operational, on-site engineering support. Develop and implement a succession planning process.

# FINAL REPORT
# CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES

Prepared for:

**Newfoundland and Labrador Hydro**
**St. John's, NL**

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Stantec

**FINAL REPORT**
**CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS**
**HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES**

# Executive Summary

Stantec (formerly Neill and Gunter) conducted a Condition Assessment and Life Cycle Cost Analysis Study of the Newfoundland and Labrador Hydro ("HYDRO") Hardwoods and Stephenville Gas Turbine Facilities over the period July through December 2007. The Gas Turbines at each site have been in service since the mid 1970's. The objective of the Study is to provide HYDRO with recommendations on the best course of action to achieve a high degree of operating reliability at each site, at least cost, for a further 15 years of operation.

During the Study period meetings were held with HYDRO officials, visits were made to each site and available HYDRO documentation was reviewed in order to assess the current condition of the equipment and structures at each site and determine the best course of action to allow a further 15 years of reliable service. The Gas Turbines at each site have operated over the years primarily as synchronous condensers providing MVAR support of system voltage. While the Gas Turbines can provide 50 MWs of emergency generation capacity, there has been very little generation provided by the units over the past 30 years. Refer to Report Section 2 for an overview of the Gas Turbine Facilities at each site.

The Gas Turbine Facilities consist of major equipment such as the gas generator engines, power turbines and alternator supported by balance-of-plant auxiliary systems such as the oil fuel supply system; lube oil system; electrical systems (switchgear; motor control centres, dc batteries); control & instrumentation systems (distributed control system; temperature and vibration monitoring equipment). Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of components that make up the Gas Turbine Facilities at each site.

The condition assessment portion of the Study found that the gas generator engines and power turbines at each site show signs of operational wear and will require remedial work to allow reliable operation over the next 15 years. Since HYDRO was unable to provide any historical electrical testing data or visual inspection information on the alternator at either site, it was not possible to assess the current condition of either alternator and determine the extent of remedial work required to allow reliable operation over the next 15 years. HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the alternator's stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. The existing balance-of-plant system equipment, buildings and structures at each site are generally in good condition however there is some degree of minimal refurbishment work required in these systems. Refer to Report Section 5 (Hardwoods) and Section 6 (Stephenville) for details on the condition assessment of each Gas Turbine Facility.

A review of the Operator's Logs provided by HYDRO, particularly over the past 5 years of operation, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting

from sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator and in the balance-of-plant systems. These sporadic issues are deemed fixable with the proper allocation of time, resources and budget. Refer to Report Section 4 for details on these operational issues.

In response to the findings of the condition assessment portion of the Study, options studied to provide reliable operation over the next 15 years included: (i) the refurbishment of the existing equipment and structures at each site; (ii) the replacement of specific major equipment items (gas generator engines, power turbines and alternator) with new equipment as well as the refurbishment of balance-of-plant systems at one or both sites; (iii) the addition of a new gas turbine to replace one or both existing gas turbines and (iv) for HYDRO's consideration, the addition of a dynamic var compensator (D-VAR) to replace one or both gas turbines for system MVAR support only, the dominant operating mode of the Gas Turbines over the past 30 years. Refer to Report Section 7 for details on the costs and technical aspects of the Options considered.

The 15 year life cycle cost analysis study of each Option included capital costs for engineering, equipment supply and installation, as well as fuel, operational and maintenance costs at each site. The 15 year life cycle cost analysis of each Option was performed using HYDRO's Cost/Benefit Financial Analysis Model which uses the Cumulative Net Present Value (CPW) approach to perform economic analyses comparisons of alternatives. Refer to Report Section 8 for details on the life cycle cost analysis of the various life extension Options considered. The following Table provides a summary of the Options evaluated and the ranking and CPW of each Option.

**15 Year Life Extension Options**
**Cumulative Net Present Value (CPW)**

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 1 | Option 4 – DVAR | $8,995,597 | $8,995,597 |
| 2 | Base Case 2B- Stephenville Refurbishment - No GT Rental | $9,548,569 | $24,996,028 |
| 3 | Base Case 1B- Hardwoods Refurbishment - No GT Rental | $11,467,914 | $26,930,650 |
| 4 | Base Case 2A- Stephenville Refurbishment - GT Rental | $13,842,768 | $27,711,405 |
| 5 | Base Case 1A- Hardwoods Refurbishment - GT Rental | $16,010,747 | $29,894,660 |
| 6 | Option 2 – New Alternator/Refurbish Engines & Turbines – GT Rental | $16,248,954 | $28,574,070 |
| 7 | Option 1 – New Engines & Turbines/Refurbish Alternator – GT Rental | $33,088,681 | $36,221,835 |
| 8 | Option 3 – Complete New GT Unit | $38,145,919 | $38,145,919 |

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A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023 (the specified 15 years of further service) has not been determined by HYDRO at this time. The financial analysis results in the Table reflect two scenarios beyond 2023. The first scenario (Sub-Case 1) assumes further refurbishment work in 2023, whereas the second scenario (Sub-Case 2) assumes the equipment will generally be totally replaced in 2023 with new equipment. The two scenarios however do not affect the overall ranking of the Options.

While Option 4, the Dynamic VAR Compensator (D-VAR) addition at one site, is ranked 1 in the Options considered, primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis of this Option are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. In this Option, a D-VAR would replace a gas turbine at one or both sites for MVAR system voltage support only. The question that HYDRO must address regarding this Option is whether backup emergency generating capability is absolutely required at either site going forward. If the answer is yes, this Option can be dismissed from further consideration. If the answer is no, then a more detailed study of this Option should be conducted with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options 1 and 2 for MVAR system voltage support only, should HYDRO decide to forego generation capability at either site. Refer to Report Section 7 for details on the application of D-VAR technology.

The Base Case Options (1A/1B – Hardwoods) and (2A/2B – Stephenville) rank 2, 3, 4 and 5 of the Options studied. These Options, involving the refurbishment of the existing equipment at each site, assume the alternator will have to be extensively refurbished off-site at a supplier's facilities, over an estimated 4 month period. As noted previously, HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. Base Cases 1A and 2A assume that HYDRO will rent a mobile gas turbine to cover the alternator refurbishment period, whereas Base Cases 1B and 2B assume that HYDRO will schedule an estimated 4 month outage at each site when the alternator is being refurbished. The decision on the use of a rental unit is HYDRO's.

Option 2, ranked 6 of the Options studied would only be considered if pending a thorough testing and visual inspection of the alternator, it is determined the alternator cannot be refurbished and replacement is necessary to allow reliable operation over the next 15 years.

Options 1 and 3 ranked 7 and 8 respectively, have high CPWs and are not be considered as Options to pursue.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and

structures can be refurbished sufficiently to allow reliable operation over the next 15 years. It is recommended that Base Case Options 1 and 2 at each site be pursued with a decision required on whether a rental mobile gas turbine will be employed at each site. Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. If replacement is necessary at one site or the other, then Option 2 should be pursued.

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# 1.0 INTRODUCTION

## 1.1 GENERAL

Newfoundland and Labrador Hydro ("HYDRO") issued a Request for Proposals ("RFP") Contract Agreement 2007-35410-OQ on May 23, 2007 requesting Proposals for all work required to perform a condition assessment and life cycle analysis on gas turbines facilities located at Hardwoods, in the St. John's area, and Stephenville, Newfoundland and Labrador. Neill and Gunter (Nova Scotia) Limited ("NG") was awarded a Contract for this work on July 6, 2007. Following the award of the Contract, Neill and Gunter was acquired by Stantec Consulting Ltd. ("Stantec") on October 19, 2007. The Contract was subsequently assigned to Stantec by HYDRO.

The purpose of the Study is to provide HYDRO with a comprehensive Report that can be used as the basis in deciding the best course of action to achieve a high degree of operating reliability, at least cost, for the next 15 years at each site.

This Final Report presents the findings of a Condition Assessment and Life Cycle Cost Analysis Study of the Hardwoods and Stephenville Gas Turbine Facilities carried out by Stantec over the period July through November 2007. The Report documents Stantec's observations and comments from a site visit to Stephenville on July 17/18, 2007, a site visit to Hardwoods on August 21/22, 2007, a review of the documentation provided by HYDRO and discussions with HYDRO personnel during and following the site visits.

This Report is presented in ten sections. Section 1 outlines the scope of work, study methodology and information sources. Section 2 provides an overview of each Gas Turbine Facility and the equipment assessed. Section 3 presents a discussion on reliability, availability and maintainability (RAM) as it relates to the gas turbine and alternator. Section 4 reviews some of the operational issues affecting the performance of both Gas Turbines and the inspection and maintenance activities at each site. Section 5 provides a condition assessment of the equipment, buildings and structures at Hardwoods and Section 6 provides a similar assessment for the Stephenville site. Section 7 explores the options available for the 15 year life extension of both Gas Turbine Facilities. Section 8 presents a life cycle cost analysis of the various options. Section 9 provides the Study conclusions and recommendations. Section 10 relates to closure.

The Report presents a multi-disciplinary engineering condition assessment of the Gas Turbine Facilities and a life cycle cost analysis of refurbishing the existing units as compared to other options available to HYDRO for continued reliable operation at each site. The boundaries of the Study extend from the Fuel Unloading area up to the low voltage bushings of the Gas Turbine 13.8/66 kV step-up transformer at each site.

The focus of the technical aspects of the Study consisted of an evaluation of plant equipment, systems and components from an operational reliability, equipment availability and maintenance perspective in order to determine which components may require upgrade, replacement or repair due to equipment obsolescence, equipment ageing effects or maintenance practices in order to provide reliable operation over the next 15 years.

The focus of the life cycle cost analysis aspects of the study consisted of an economic evaluation of the costs associated with refurbishing the existing equipment, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis included capital costs for equipment supply and installation as well as maintenance and operational costs at each site. As agreed with HYDRO, the future operational mode of each unit on an annual basis will reflect its annual operation over the past 5 years.

An Interim Report on the Stephenville Gas Turbine Facility was issued on August 17, 2007. An Interim Report on the Hardwoods Gas Turbine Facility was issued on October 3, 2007. The Condition Assessment sections of each Interim Report have been incorporated in the Final Report. The Life Cycle Cost Analysis section of the Final Report is a new section not previously issued.

## 1.2 SCOPE OF WORK

The Condition Assessment and Life Cycle Cost Analysis of the Hardwoods and Stephenville Gas Turbine Facilities includes the following work scope as contained in the HYDRO Request for Proposal (RFP) Contract Agreement 2007-35410-OQ dated May 23, 2007.

- Perform a detailed assessment of the condition of the Hardwoods and Stephenville Gas Turbine Facilities. The assessment will identify potential problems in continuing to operate the Facilities as they presently exist for the next 15 years. Potential problems will include availability of service support by manufacturers. The study will recommend solutions with associated cost estimates for maintaining and running the Facilities as reliable generating units for that time period.

- Conduct Site investigations and inspections which will include where required opening and/or disassembly of major equipment components for internal inspection. The study shall focus on the Gas Turbine Facility in its entirety which shall include the fuel unloading system, storage and distribution system, fuel forwarding module, control module, air intake structures, gas turbines, power turbines, exhaust stacks, building enclosures, clutches, alternator, exciter, control systems, power systems, and auxiliary systems (i.e. compressed air, lube oil, glycol, etc.).

- Review information provided by HYDRO regarding significant upgrades or maintenance work performed on the Hardwoods and Stephenville Gas Turbine Facilities in the past for consideration in making assessments (i.e. gas turbine overhaul reports, alternator upgrades, etc.) on operating reliability over the next 15 years.

- Review information provided by HYDRO regarding current operating problems at the Hardwoods and Stephenville Gas Turbine Facilities for consideration in making assessments of operating reliability over the next 15 years.

- In addition the study will evaluate two other options for redeveloping the Hardwoods and Stephenville sites as follows:

Option 1: Replace the major equipment items and systems with new at one site. Existing infrastructures would be utilized where considered to be suitable for continued long term use. The components removed would be used as spares for the other site.

Option 2: Replace major equipment items and systems with new at both sites. Existing infrastructures would be utilized where considered to be suitable for continued long term use.

- Provide HYDRO with a comprehensive report that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at the Hardwoods and Stephenville Gas Turbine Facilities.

The Hardwoods and Stephenville Gas Turbine Facilities are located at terminal stations. The Study does not include equipment and structures that are part of the terminal station such as transformers, switchyard circuit breakers, etc. The Study also does not include the Gas Turbines SCADA remote control and monitoring equipment.

## 1.3 CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS METHODOLOGY

Stantec's approach or methodology in conducting the Gas Turbine Condition Assessment and Life Cycle Cost Analysis Study consisted of three phases.

*Phase 1 involves* -- (i) the visual inspection of the equipment, (ii) a review of operation and maintenance history, (iii) a review of data from regularly scheduled tests and inspections carried out on equipment and (iv) a review of equipment documentation – manuals, drawings, etc. Refer to Report Sections 4.0, 5.0 and 6.0 for details.

*Phase 2 involves* -- (i) an assessment of the data collected from Phase 1, (ii) compiling a list of recommended refurbishments to the existing equipment to allow for reliable operation over the next 15 years, (iii) source pricing on the refurbishments, (iv) prepare a performance specification and obtain pricing on the Study options ie replace the major equipment items and systems with new at one or both sites. Refer to Report Section 7.0 for details.

*Phase 3 involves* -- a life cycle cost analysis of (i) the refurbishment of the existing Gas Turbine Facilities and (ii) the Study options. This will require information from HYDRO on (i) historical maintenance and operations costs (ii) forecast of unit operation over next 15 years (iii) cost of capital, etc. Refer to Report Section 8.0 for details.

This methodology will provide HYDRO with a comprehensive report that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at the Hardwoods and Stephenville Gas Turbine Facilities.

## 1.4 INFORMATION SOURCES

Information for the Condition Assessment Study was sourced in a number of ways.

### 1.4.1 Meetings and Discussions with Newfoundland and Labrador Hydro

Kick-off Meetings were held concurrently with the visits to each site. A Stephenville Kick-off was held on July 17/18, 2007. A Hardwoods Kick-off was held at HYDRO offices in St. John's on August 21, 2007. A copy of the Minutes of each Meeting is included in Appendix 1. The Kick-off Meetings provided a good introduction for Stantec to the Hardwoods and Stephenville Gas Turbine Facility sites and various operational issues under consideration by HYDRO.

A list of HYDRO and Stantec personnel involved in the Study is included in Appendix 1.

### 1.4.2 Site Visits

A site visit followed the Kick-off Meetings. Stantec personnel, accompanied by HYDRO personnel, spent parts of July 17 and 18 at the Stephenville site and August 21 and 22 on the Hardwoods site inspecting the Gas Turbine Facility equipment and related civil, mechanical, electrical, instrumentation and control systems. Observations from the visit are documented in Sections 4.0, 5.0 and 6.0 of this Report.

### 1.4.3 Gas Turbine Plant Documentation

Stantec provided HYDRO with a List of Documentation required for review. The Final Report reflects documentation received as of November 15, 2007. Information requested for review included but was not limited to:

- Gas Turbine Facility Maintenance Records
- Gas Turbine Facility Operational Logs & Forced Outage Information
- Gas Turbine Facility Major Refurbishment/Overhaul Work Reports
- Equipment Inspection Reports including Oil Tanks (all equipment over past 10 years)
- Equipment Test Reports (all equipment over past 10 years)
- Gas Turbine O&M Manual
- Electrical Equipment O& M Manuals
- Control Equipment O&M Manuals
- Control System Architecture including communication links
- Programming software and platforms per control system
- Various Drawings
- List of major Spare Parts in inventory at Site
- List of existing parts/service providers for the major equipment
- Maintenance Plan and Schedule

HYDRO provided compact discs (CD's) on August 22 and September 20, 2007 containing available information on each site. A printout of the operational logs and the various maintenance Work Orders carried out at the Hardwoods and Stephenville sites was provided as well as various O & M Manuals and drawings. The area where little information was provided related to historical equipment test and inspection reports as well as reports on major refurbishment work carried out on the major Gas Turbine components – engines, power turbines and alternator. The lack of test and inspection information on the alternator in particular made the condition assessment of this equipment very difficult.

### 1.4.4 Equipment Supplier Contacts

Section 7.0 outlines a number of options considered for the reliable operation of the Hardwoods and Stephenville Gas Turbine facilities for a further 15 years. The options range from refurbishment of the existing Gas Turbine Facility equipment and structures to replacement of major components to replacement of the Gas Turbines themselves.

The following equipment suppliers were contacted for costing purposes:

- Brush Electrical Machines Ltd – Houston, USA – Mike Watkins
- MAN TURBO – Calgary, Alberta – Pierre Bovon
- Wood Group Generator Services – Louisiana – David Robinson
- Siemens Canada Limited – Dartmouth NS and Hamilton, ON – Bob Sheehan
- General Electric – Schenectady, NY – S. Wheeler

While several suppliers were responsive to our requests, many were not.

### 1.4.5 S&S Turbine Services Limited

Robin Sipe of S&S Turbine Services Limited of Fort St. John, British Columbia was a member of the Stantec team for the Condition Assessment Study. Mr. Sipe has extensive experience in the servicing and repair of Olympus C engines in particular. Mr. Sipe's experience was a valuable information source for both the Stantec team and HYDRO.

# 2.0 GAS TURBINE FACILITIES OVERVIEW

## 2.1 HARDWOODS GAS TURBINE FACILITY

The Hardwoods Gas Turbine Facility was placed in service in 1976 and operates as both a generator – peaking/emergency backup -- and a synchronous condenser, the latter being the dominant operating mode. The Gas Turbine, while averaging approximately 1000 running hours annually over its 31 years of service has experienced frequent start/stops, estimated to be in excess of 170 starts per year. A photograph of the Gas Turbine (Photo: HWD-001) is included in Appendix 13.

The Gas Turbine is located within a Terminal Station consisting of 66 kV and 230 kV bus work, circuit breakers, transformers and transmission lines. The Gas Turbine alternator output voltage of 13.8 kV is connected via enclosed bus duct to a circuit breaker located in a 13.8 kV switchgear assembly. A further run of enclosed 13.8 kV bus duct connects the circuit breaker to the LV terminals of a 13.8/66 kV, 45/60/75 MVA transformer. A System Operating Diagram and Single Line Diagram for the Hardwoods Site are included in Appendix 2.

The Facility consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS size 208T clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. Gas Generator Engine B was overhauled in 1993. Gas Generator Engine A has never been overhauled since going into service in 1976. It is our understanding that both exhaust stacks at Hardwoods were replaced in 1992.

A 53 MW 13.8 kV Brush Alternator Frame BDAX8-280 is common to and driven by either or both, Power Turbines as required. The Alternator has a rotating exciter connected to the shaft. Generator air cooling is provided by fan blades on the alternator shaft that induces filtered outside air through the stator and rotor.

The lube oil system is common to each power turbine, clutch and the alternator. Lube oil cooling is provided by an external Glycol Cooler. The Glycol Cooler for the main lube oil system is located outdoors and a single glycol circulation pump and three-way temperature control valve are located in the Auxiliary Module Building dedicated for the main lube oil storage and pump facilities. Air compressors for starting air and process purposes are also located within the Auxiliary Module Building in an enclosed room. Air receiver tanks are located outside the building.

The fuel oil system consists of truck unloading facility pump sets located in a dedicated fuel oil unloading building at the storage tank area; one storage tank of 14,000 bbl (2,225,000L) nominal capacity and a piping system between the storage tank and fuel forwarding pump sets (AC and DC motor) located in a dedicated fuel forwarding building adjacent to the Gas Turbine.

Electrical equipment consists of a 13.8 kV switchgear assembly located in an outdoor enclosure; enclosed bus duct connecting the alternator to its circuit breaker and 13.8/66 kV step-up transformer. Motor control centres (AC and DC), protection and control devices, battery charger and inverter are located in the Control Building. The 125 V DC batteries are installed in a separate battery room within the Control Building.

An ELSAG Bailey INFI 90 DCS system installed in 1997 and located in the Control Building provides the local human machine interface (HMI) and the control and monitoring functions for the Facility. The Gas Turbine is also remotely started/stopped and monitored from the Energy Control Centre located in St. John's via a SCADA system.

From information provided by HYDRO in the Request for Proposals, the operational data on the Gas Turbine is as follows:

- Gas Generator A
  - 1200 running hours since installed in 1976
  - 2100 start/stops since installed
- Gas Generator B
  - 3935 running hours since year1993 overhaul
  - 3115 start/stops since year 1993 overhaul
- Alternator
  - 27,250 synchronous condenser mode running hours

## 2.2 STEPHENVILLE GAS TURBINE FACILITY

The Stephenville Gas Turbine Facility was placed in service in 1975 and is a sister unit to the Gas Turbine at Hardwoods. Like Hardwoods, the Stephenville Gas Turbine operates as both a generator – peaking/emergency backup -- and a synchronous condenser, the latter being the dominant operating mode. Based on information provided by HYDRO, the Gas Turbine, while having minimal running time, has experienced frequent start/stops, averaging in excess of 170 starts per year, over its 30 years of service. A photograph of the Gas Turbine (Photo: SVL-001) is included in Appendix 13.

While the alternators at Stephenville and Hardwoods are similar in terms of MW output and construction, they do have several major differences.

- The Stephenville alternator cooling system uses a 50/50 glycol-water mixture to absorb heat from the air circulating inside the alternator casing and discharges the heat to ambient air by means of an external heat exchanger complete with fan cooling. The Hardwoods alternator cooling does not use an external heat exchanger. The Hardwoods cooling system consists of intake filters and discharge louvers located on the alternator enclosure. The clean air is induced into the alternator by fan blades mounted on the alternator main shaft, and is rejected from the system via exhaust louvers.

- The Stephenville alternator rotor length is 1.64 meters longer than the rotor length at the Hardwoods site.

The Gas Turbine is located within a Terminal Station consisting of 66 kV and 230 kV bus work, circuit breakers, transformers and transmission lines. The Gas Turbine alternator output voltage of 13.8 kV is connected via enclosed bus duct to a circuit breaker located in a 13.8 kV switchgear assembly. A further run of enclosed 13.8 kV bus duct connects the circuit breaker to the LV terminals of a 13.8/66 kV, 45/60/75 MVA transformer. A System Operating Diagram for the Stephenville Terminal Station is included in Appendix 2.

The Facility consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS size 208T clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. Gas Generator Engine B was overhauled in 2000. Gas Generator Engine A has never been overhauled since going into service in 1975. It is our understanding both exhaust stacks at Stephenville were replaced in 1992

A 53 MW 13.8 kV Brush Alternator Frame BDAX8-280 is common to and driven by each Power Turbine. The Alternator has a rotating exciter connected to the shaft. The lube oil system is common to each power turbine, clutch and the alternator. Lube oil cooling is provided by an external Glycol Cooler. Generator air cooling is provided by an internal air heat exchanger and an external Glycol Cooler. The two Glycol Coolers and pump sets are located outdoors.

The fuel oil system consists of a truck unloading facility; three storage tanks, each of 477,000 litre nominal capacity and fuel unloading and forwarding pump sets located in a Fuel Forwarding Building. Air compressors for starting air and process purposes are located within the Control Building in an enclosed room.

Electrical equipment consists of a 13.8 kV switchgear assembly located in an outdoor enclosure; enclosed bus duct connecting the alternator to its circuit breaker and 13.8/66 kV step-up transformer. Motor control centres (AC and DC), as well as 250 V and 125 V DC batteries, battery chargers and inverter are all located in the Control Building.

An ELSAG Bailey INFI 90 DCS system installed in 1999 and located in the Control Building provides the local human machine interface (HMI) and the control and monitoring functions for the Facility. The Gas Turbine is also remotely started/stopped and monitored from the Energy Control Centre located in St. John's via a SCADA system.

From information provided by HYDRO in the Request for Proposals, the operational data on the Gas Turbine is as follows:

- Gas Generator A
  - 3883 running hours since installed in 1975
  - 3416 start/stops since installed
- Gas Generator B
  - 2015 running hours since year 2000 overhaul
  - 1770 start/stops since year 2000 overhaul
- Alternator
  - 3765 synchronous condenser mode running hours

## 2.3 GAS TURBINE FACILITY STUDY BOUNDARIES

This sub-section lists the Gas Turbine Plant equipment and structures at each site included within the boundaries of the Gas Turbine Condition Assessment and Life Cycle Cost Analysis Study. The Study boundaries encompass:

Gas Generator Engines and Subsystems

- Rolls Royce Olympus C Gas Generator Engines (2)
  - Fuel Piping
  - Woodward Governor
  - Gas Generator Engines Lube Oil System
  - Gas Generator Engines Bearings
  - Compressed Air Starting System
- Air Inlet Systems (2)
- Exhaust Stacks (2)
- Fuel Oil System
  - Oil Unloading
  - Oil Storage and Secondary Containment
  - Fuel Forwarding Equipment
  - Fuel Piping
- Gas Generator Engine and Power Turbine Enclosures (2)
- Fire Fighting Systems

Power Turbine, Alternator (Generator) and Subsystems

- Curtiss Wright Power Turbines (2)
- S.S.S. Power Turbine Clutches (2)
- Bearings
- Main Lube Oil System (common to the Power Turbines, Clutches and Alternator Bearings)
- Main Lube Oil Cooling System / Glycol Cooler
- Alternator Air Cooling System
- Alternator (Generator)
- Rotating Exciter
- Automatic Voltage Regulator (AVR)
- Alternator (Generator) Enclosure
- Fire Fighting System

Electrical Ancillaries

- 13.8 kV Switchgear (alternator breaker)
- Alternator Output Bus Duct
- Alternator protection relays
- Sync-check relay
- Motor Control Centres (AC & DC)
- Station DC supply (batteries and chargers)
- Inverter (AC supply for control systems)
- Emergency Backup Diesel Generator

Instrumentation and Control

- Bailey Control System
- SCADA interface (remote control and indication)
- Temperature monitoring system
- Vibration monitoring system
- Auxiliary Systems Instrumentation Devices
    - Fuel oil tanks
    - Fuel forwarding system
    - Compressed Air System
    - Glycol cooling system
    - Lube oil system

Buildings

- Gas Turbine Control Building (both sites)
- High Voltage Switchgear Building (both sites)
- Fuel Unloading Building (Hardwoods)
- Fuel Forwarding Building (Hardwoods)
- Auxiliary Module Building (Hardwoods)
- Maintenance and Parts Storage Building (Hardwoods)
- Fuel Unloading and Forwarding Building (Stephenville)
- Parts Storage Shed (Stephenville)
- Waste Oil Storage Shed (Stephenville)
- Emergency Backup Diesel Generator Building (both sites)

A condition assessment of the equipment and structures along with refurbishment recommendations is contained in Section 5.0 for Hardwoods and Section 6.0 for Stephenville.

# 3.0 RELIABILITY, AVAILABILITY, AND MAINTAINABILITY (RAM)

HYDRO's requirements for reliability, availability and maintainability (RAM) are major factors in the decision making process for the Options presented to ensure continued operation of the Facilities for the next 15 years. In this section of the Report, the factors that contribute to the RAM of the Facility are explained.

## 3.1 GAS TURBINE RAM PERSPECTIVE

### 3.1.1 Review of Performance Degradation Factors

The Hardwoods and Stephenville Gas Turbines mechanically consist of gas generator engines, power turbines and clutches (collectively the gas turbine unit). There are a number of factors that impact on the performance and reliability of this equipment. The basic factor is the mode of operation that can range from base load through to peaking and emergency stand-by. Most commonly, simple cycle gas turbine facilities such as those at the Hardwoods and Stephenville sites are used for peaking, emergency stand-by and synchronous condenser operation. However, installations designed and used regularly for synchronous condenser operations are a rarity.

The unit operating mode and external operating environment determine the working environment of the gas turbine parts. The unit operating conditions refer to the start/stop cycle, power load setting, and type of fuel. The start/stop cycle can be normal load start/stop, part load start/stop, emergency start/stop, fast load start/stop, synchronous condenser start/stop and trips. The following site factors impact upon the performance of the gas turbine:

- Ambient conditions and site elevation
- Inlet and exhaust loss
- Fuel
- Performance enhancement additions

The unusual operating requirements of these simple cycle gas turbine units suggest that their maintenance requirements will be different from the norms of the power generation industry. From the discussions and review of the Hardwoods and Stephenville maintenance procedures to date, it appears that formalized inspection plans have only been applied to these units in recent years. However, the facilities have given good service and are worthy of consideration for continued operation.

#### 3.1.1.1 Gas Turbine Based Power Plant Ageing

Gas turbine engines, power turbines and clutches accumulate degradation as they accumulate operating hours, and the number of start/stop cycles. Power output and heat rates deteriorate and the failure rates increase in some sort of relationship that reflects the specifics of the site.

The hot parts of the engine are working under severe environmental conditions, namely, high flow rate, hot gases, and frequent temperature changes due to start-up and shut-down, and therefore they can have a relatively short lifespan. The hot gas path parts include combustion liners, end caps, fuel nozzle assemblies, crossfire tubes, transition pieces, turbine nozzles, turbine stationary shrouds, and turbine buckets. The damage accumulation of the buckets of a gas turbine firing at peak load will be faster than those firing at base load or part load, and therefore more significant ageing would result on a higher capacity factor plant.

#### 3.1.1.2 Major Factors that Affect Equipment Life

The gas turbine's life is affected by many factors, and the mechanism of how these factors affect equipment life has to be well understood to produce effective maintenance planning and to project its life expectancy. The most important factors include starting cycle, power setting, and type of fuel. These factors have a direct impact on the life of critical gas turbine parts, and therefore they influence the maintenance interval.

*Fuel type and quality*--- For distillate fuelled facilities like Hardwoods and Stephenville, the consideration is that the fuel is derived from crude oils that contain corrosive elements such as sodium, potassium, vanadium and lead. Distillate fuels generally release higher amounts of radiant thermal energy, which results in a subsequent reduction in combustion hardware life. The corrosive elements lead to accelerated hot corrosion of turbine nozzles and buckets. Distillate fuels do not generally contain high levels of corrosive elements, but trace quantities of contaminants can be present in these fuels, which lead to higher maintenance requirements than with natural gas fuel.

*Load Setting*---Firing temperature co-relates with the load setting of the gas turbine unit. Under higher firing temperatures, the hot gas path parts are subjected to higher temperature hot gas, and this leads to high metal temperature, which reduces hot gas path components lives. However, a reduction in load does not necessarily mean an equivalent reduction in firing temperature, so there is always some degree of effect.

*Cyclic effects*---The cyclic effects introduced during the frequent startup, operation, and shutdown of the gas turbine unit affect component life. There appears to be a requirement almost daily for these units to be started and run as Synchronous Condensers. Also, operating conditions other than the standard startup and shutdown sequence can potentially reduce the life of the hot gas path parts, rotors, and combustion parts. The starting cycle results in the most severe hot end thermal gradients experienced during normal engine operation. At ignition, the combustor exit temperature exceeds that during normal operation for a short time until the control system regulates the fuel and air flows to lower it. Therefore, the oxidation and corrosion experienced by the hot gas path is most severe at this time and will add to the engine ageing process. Frequent start/stops will further increase the ageing process.

### 3.1.1.3 The Accumulated Damage Mechanism

The causes of wear of hot gas path components of peaking plants due to cyclic duty application include thermal mechanical fatigue, high-cycle fatigue, rubs/wear, and foreign object damage. Another example is when the gas turbine experiences a trip rather than a normal base load shut down. This results in a more precipitous reduction in temperatures that promotes the development of cracks. Turbine trips (shutdown of the turbine) occur when the protective functions of the control system act as a result of detecting such events as: electrical protection trip, over speed, over temperature, high rotor vibration, fire, loss of flame, or loss of lube oil pressure.

The lengths of cracks that manifest in the hot gas parts are used as an indication of the safety of continued operation of the unit. If cracks appear on the rotating components (discs and blades), it is risky to continue operating the machine. Cracks on the stationary components can be tolerated provided they do not form a combination wherein a portion of material can be released into the gas stream. From this, it can be inferred that a scheduled frequency of borescope inspections should be in place for these units. The basis should be related to the number of starts together with the number of running hours. The precise formula that incorporates these parameters requires review of past operating experience and the results of inspections.

A certain limit for the crack length is set for a particular type of part, and a hot gas part whose crack length is beyond this limit is scheduled a repair or replacement. For peaking gas turbine units, thermal mechanical fatigue is the dominant limiter of life and understanding the interaction between thermal mechanical fatigue, creep, oxidation, and corrosion is necessary for estimating the overall life expectancy for gas turbines.

### 3.1.1.4 Performance Degradation

All types of turbo-machinery experience losses of performance with time. Even under normal operating conditions, with a good inlet air filtration system and using a clean fuel, the engine flow path components will become fouled, eroded, corroded, covered with rust scale, damaged, etc. The result will be degradation in engine performance, which will get progressively worse with increasing operating time. Thus, the gas turbine performance deteriorates as its operating hours accumulate, and the economic impact of engine performance degradation is significant. The majority of the power loss in a gas turbine is due to compressor degradation.

Gas turbine performance degradation can be classified as recoverable and non-recoverable losses. Recoverable losses are usually associated with compressor fouling and can be partially rectified by water washing. The non-recoverable losses would be due to degradation of the blades that would have to be re-conditioned or replaced to restore performance. Remember that performance degradation is a function of the operating mode, therefore the specific operating modes for these HYDRO units should be considered for performance degradation rate prediction and modeling.

Detection of the extent of the performance degradation is necessary before appropriate actions, such as online water wash or off line water wash, be taken. This infers data acquisition and assessment that would call for more instrumentation than exists on these units. Economic consideration is an important factor for determination of the optimal frequency of engine cleaning frequency. Some experts recommend that the compressor should be water washed when the estimated mass flow decrease reaches the 2 to 3% level. HYDRO could install instrumentation to monitor LP compressor efficiency. Once efficiency drops to a predetermined point, say 2%, a water wash request comes up as an operator alert. To incorporate this feature, five data points are required:

- Mass airflow (bellmouth depression reading)
- Inlet air temperature (RTD in bellmouth)
- Outlet air temperature (RTD or thermocouple in LP compressor outlet casing)
- Inlet pressure (piggybacked onto bellmouth depression)
- Outlet pressure (LP compressor discharge pressure)

#### 3.1.1.5 Reliability Degradation

Operational risk is evaluated as the product of probability of system failure and the economic consequences of system failure. The gas turbine reliability is subject to degradation, and the degradation rate depends on the same factors as for performance degradation. However, it must be noted at the Hardwoods and Stephenville sites that the simultaneous forced outage of both gas generator engines and power turbines is a rarity, and the alternator has a very high reliability record. Industry indicates that 90% of all unscheduled shutdowns are caused by faulty electrical and control components in auxiliary systems.

The gas turbine unit is subject to increasing operational risk as its operating time accumulates. To reduce the risk, some of the parts need to be repaired or replaced when the accumulated damage reaches limits that are machine design specific. Therefore, to assess the operational risk of failure of a gas turbine unit and to schedule a reasonable maintenance interval, the damage accumulation mechanism needs to be fully appreciated.

The damage accumulation process is highly dependent on the operating history (unit usage) of the system. A good appreciation of the interdependency of the damage accumulation mechanisms due to cyclic duty application and continuous duty application is necessary for accurate accumulative damage modeling. Damage limit is the criterion for maintenance decisions. From this, it can be seen that a detailed review of the combination of operating history and the level of deterioration that it produced, is key to designing an outage plan for the units.

### 3.1.2 Preventive Maintenance, Planning and Scheduling

It has been addressed above that the gas turbine unit reliability is greatly influenced by the operating conditions. A reliability model, which is able to address the influence of operating conditions, is desirable for further maintenance analysis. Furthermore, such a model would allow the plant operator to make a forecast of reliability given a future operating profile. However, most of the reliability models that are currently available consider the calendar time or service time as the only parameters that influence the reliability characteristics of machinery during its operation. However, for HYDRO's gas turbines, the system age evolves as a function of a site specific utilization pattern.

The decision governing the timing of maintenance inspections is two-dimensional, one is to determine when the next inspection should occur, and the other is to determine the degree of intrusiveness that the maintenance work scope should take, i.e., what maintenance action to take. A factor in this Study is a review of the preventive maintenance that was carried out in the past in order to obtain an appreciation of how the current status has evolved. Also, to extrapolate the history of maintenance items and their costs to predict what can be expected over the next 15 years. This implies a projected maintenance schedule that takes into account a HYDRO defined target for the reliability, availability, and maintainability (RAM) of each of the units.

The operating conditions for the HYDRO gas turbines do not fit maintenance routines that are based on a fixed time interval that are in accordance with recommendations from the power plant supplier. A unit specific maintenance philosophy is therefore needed for effective gas turbine maintenance scheduling. For the unit specific maintenance approach, accurate historical reliability information and performance degradation for each gas turbine is necessary. Unfortunately in the case of the Hardwoods and Stephenville Gas Turbines such historical and performance degradation information does not appear to be available.

The historical maintenance practice has a strong impact on current engine performance and restoration requirements. Practices to restore performance and reliability would include; online water wash, off line water wash, combustion inspection/refurbishment, hot gas path inspection, and major inspection, steam cleaning, abrasive cleaning with hand scouring, and replacement of hot gas path parts with refurbished or brand new parts.

### 3.1.3 Advanced Technology

Application of new gas turbine technology is also an option for performance and reliability restoration. Advanced technology packages can improve efficiency, increase output, or extend maintenance intervals. HYDRO may consider individual upgrade packages such as new modern engines, power turbines and alternator as well as an entire new modern gas turbine to enhance the performance of its generating units, based on the increasing demand, needs of improving efficiency, or maintenance considerations.

A full evaluation of the economic benefit of advanced technology packages would require the consideration of the technical factors of the power plant, which include its configuration, performance, and reliability characteristics, and external market signals, such as price of fuel and price of electricity, future electric power demand and supply, electricity sales and fuel purchase contracts stipulations, etc. While this Study will consider several advanced technology options, the analysis will be high level and will be used for comparison purposes only against the refurbishment option.

## 3.2 ALTERNATOR/EXCITER RAM PERSPECTIVE

During operation, alternators are continuously subjected to electrical, mechanical, thermal and environmental stresses. These stresses act and interact in complex ways to degrade the machine's components and reduce its useful life.

The life expectancy of an alternator depends upon its mode of operation, design, maintenance practices and operating incidents. Alternators that are operated as peaking units with many start-stops and also with high MVAR loads (high field currents), when in synchronous condenser mode, generally have a lower life expectancy – much shorter than a base load unit with few start-stops and operating near unity power factor with lower field current. Frequent start-stops expose the alternator to thermal stress due to heating and cooling cycles. This thermal cycling can reduce the life of the alternator and affect reliability. More frequent start-stops also tend to induce more mechanical wear on the insulation and will lead to more long term distortion on the copper conductors.

Alternators that operate primarily as base load units can expect to have an average useful life of approximately 30 years. On the other hand, alternators that see frequent start-stops and/or load cycling can expect to have a much shorter lifespan. Unfortunately, there is no exact formula to determine the useful life of a frequent start-stop machine; however, a unit operated in a frequent start-stop mode can expect an insulation life of from 30 to 50% that of a base load unit.

With the type of operation the Hardwoods and Stephenville alternators have been subjected to over the years – frequent stop/starts and synchronous condenser mode operation - expectations are that the stator core, stator and rotor windings/insulation, rotor retaining rings/end caps and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years

In order to assess the condition and life expectancy of an alternator and its excitation system, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Refer to sub-sections 5.3.5 and 6.3.5 for further details on the type of tests and inspections that are typically carried out on an alternator as part of ongoing inspection and maintenance programs. Unfortunately for the purposes of this Study HYDRO was unable to locate information on

electrical test data and inspections carried out on the alternators at either site over their 30 plus years of service, making condition assessment very difficult.

In addition, the frequent requirement to have the alternator available for service makes access for maintenance and testing difficult. This also raises serious concerns for providing the same type of availability for the next 15 years as has been experienced in the past. HYDRO must establish with its System Operations group defined intervals where outages are scheduled to carryout regular tests and inspections of the alternator and its excitation system.

The configuration of the Hardwoods and Stephenville Gas Turbines includes two engines, two power turbines and only one alternator. This makes the alternator a critical component in the availability and reliability of the Gas Turbines at each site. An alternator problem therefore can result in major unplanned outages.

# 4.0 GAS TURBINE FACILITY OPERATIONAL ISSUES AND MAINTENANCE

## 4.1 GENERAL

The Gas Turbine Facilities at Hardwoods and Stephenville have been in operation since the mid 1970's. While operational issues and maintenance information for the early years of operation were not available, HYDRO did provide a copy of the Operator's Logs for each site covering the period 1992 to 2007. In addition, HYDRO provided an extensive listing of work orders extracted from the J D Edwards work order system covering the period 1999 to 2007.

## 4.2 OPERATIONAL ISSUES

A review of the information provided, particularly over the past 5 years, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting from:

- Sporadic mechanical and electrical equipment issues in balance-of-plant systems such as the fuel forwarding system; air compressor system; glycol cooling system; inadequately rated interposing relays, etc.
- Sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator such as exhaust gas temperature (EGT) spread in the engine burner system; clutch failed to engage or disengage; anti-icing issues; vibration trips; deflector rings disengageing; alternator reverse power trips; etc.

A copy of a HYDRO email of July 13, 2007 illustrating various ongoing troublesome sporadic operational issues at each site is included in Appendix 3.

The nature of these sporadic operational issues is such that any one issue might result in a failed start on a particular startup but not on the next. Many of the start failures and trips were often due to repetitions of the same initiating event. The failed starts occur whether the Gas Turbines are started locally or remotely from the Energy Control Centre (ECC) in St. John's. It appears there are also insufficient indications/alarms of the Gas Turbine operation taken back to the ECC. There should be a full review of inputs to the distributed control system (DCS) to determine the adequacy of alarm functions in general and inhibits particularly to the ECC.

The purpose of the condition assessment study is to identify potential problems in continuing to operate the Gas Turbine Facilities as they presently exist and identify solutions for maintaining and running the Facilities as reliable generating units for the next 15 years. While the Study, in conjunction with input from HYDRO, serves to highlight these sporadic operational issues, the Study schedule, budget and scope did not allow for a detailed investigation and resolve of these numerous ongoing sporadic operational issues.

Operational issues, particularly in the balance-of-plant mechanical, electrical and control systems are readily identifiable and fixable if the proper resources and budget are applied. From the information provided, it appears that HYDRO in the past has addressed these operational issues on an ongoing ad hoc basis rather than on a concerted overall project approach basis. To address these sporadic operational issues, several recommendations follow:

- It is recommended that HYDRO, as part of the Gas Turbines Refurbishment Project, assemble a dedicated in-house multi-disciplinary engineering team with responsibility to oversee the entire Refurbishment Project at each site.

- For the balance-of-plant mechanical, electrical and control systems sporadic problems in particular, it is recommended that HYDRO, as part of the overall refurbishment budget at each site, allocate an amount of money to address and resolve the sporadic operational issues in these systems. It is suggested that a preliminary budget amount of $250,000 be allocated for each site to cover the labour, expenses and material costs associated with addressing these balance-of-plant operational issues. The budget figure can be finalized following an initial detailed investigation by the refurbishment project team.

- For the sporadic operational issues pertaining to the major equipment – engines, power turbines and alternator - where repeated maintenance has not solved the problem, the major refurbishment recommendations and associated budget costs, arising from the Condition Assessment Study, are intended to address these issues. Report Section 7.0 provides details on these recommendations.

In summary, a dedicated project team with the proper resources, budget and schedule is necessary to properly carryout the refurbishment work at each site to provide reliable operation of the generating units over the next 15 years.

## 4.3 FACILITY INSPECTION AND MAINTENANCE

HYDRO provided a copy of the daily, weekly, semi-annual, annual, 5 year and 6 year inspection check lists governing inspections carried out on the Gas Turbine equipment at each site. The lists are included in Appendix 5. While only a few completed inspection check lists were available for review, it is assumed that such inspections are regularly carried out at the intervals noted. A review of these inspection check lists shows that with the exception of the 6 year protection and control (P&C) inspection, most inspections are of a mechanical nature. There are no electrical tests or visual inspections of the alternator (stator/rotor/exciter) listed on any of these check lists. Further, HYDRO was unable to provide historical electrical test data on the alternators at either site. It is recommended that HYDRO incorporate alternator tests and inspections similar to those listed in sub-sections 5.3.5 and 6.3.5 in these inspection lists on a go-forward basis.

As noted above, HYDRO provided an extensive listing of maintenance work orders extracted from the J D Edwards work order system covering the period 1999 to 2007. Many of the items

listed in the JD Edwards printout could be categorized as routine maintenance considering the age of the Gas Turbine equipment and devices. There have however been a number of major work orders such as the replacement of the control systems at both sites with the ELSAG Bailey INFI 90 DCS system in 1997 (Hardwoods) and 1999 (Stephenville); a new AVR system at Hardwoods in 2006; refurbishment of one gas generator (engine) at each site in 1993 (Hardwoods) and 2000 (Stephenville) and rotor refurbishment work at Hardwoods in 1995. A listing of the major work carried out at each site is included in Appendix 3. Available Reports on the major refurbishment work carried out at each site over the 30 years of Gas Turbines operation were few. Several Reports on alternator rotor refurbishment work at Hardwoods were available, however there were no similar alternator refurbishment Reports available for Stephenville. The absence of major refurbishment Reports could indicate either no other major refurbishment work, other than that listed in Appendix 3, was carried out at each site over the past 30 years or the Reports could not be found.

# 5.0 HARDWOODS GAS TURBINE FACILITY CONDITION ASSESSMENT

## 5.1 GENERAL

This Section documents Stantec's observations and comments on the condition of equipment and structures at the Hardwoods Gas Turbine Facility. These comments are based on observations during the site visit on August 21/22, 2007, discussions with HYDRO staff and a review of documentation provided by HYDRO. Photographs taken during the site visit are included in Appendix 13. The Facility was broken down into the following areas for the condition assessment study:

- Gas Generators / Power Turbines and Auxiliary Systems
- Alternator / Excitation System
- Fuel Oil System
- Electrical Systems
- Control & Instrumentation Systems
- Buildings

This Section contains a number of recommendations on refurbishment work that HYDRO should consider in order to provide for the reliable operation of the Facility (Photo: HWD-001) for a further 15 years. **The recommendations and associated costs are summarized in Appendix 6.**

## 5.2 GAS GENERATORS/POWER TURBINES AND AUXILIARY SYSTEMS

### 5.2.1 Rolls Royce Olympus C Gas Generator Engines A & B

The Gas Turbine consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with an SSS clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. New Olympus C Gas Generator Engines are no longer available from Rolls Royce. At the present time there are approximately 14 Olympus C Gas Generator Engine assemblies available in the market. In addition to the refurbishment of the existing Gas Generator Engines as recommended herein and in line with HYDRO's plans to keep the Gas Turbines at both sites operational for a further 15 years, it may be advantageous for HYDRO to consider obtaining a whole spare engine assembly as eventually all the spare Olympus C units will be scrapped.

The Olympus "C" type 2022 gas generator is a straight flow tubo-jet employing axial flow compressors driven by an axial flow turbine. A diagram (Figure 2-3) illustrating a cross-sectional view of the Olympus C Gas Generator is included in Appendix 4 to illustrate the various components comprising the Gas Generator. The combustion system uses eight combustors

each with a burner contained in an annular outer casing. The eight combustion chambers are arranged equidistant around the turbine numbered from the top clockwise when viewed from the rear. An external air compressor system provides air to the starter motors. A Woodward Electronic Governor controls fuel flow. Further details on the Gas Generator auxiliary equipment can be found in sub-section 5.2.2.

Provision is made for heating the compressor entry guide vanes, nose fairing and the leading edges of the air intake casing during adverse weather conditions. The heating medium is air tapped from the #6 vane of the compressor casing and conveyed through a pipe to an electrically operated anti-icing hot air valve.

The lubricating oil system comprises an external tank that contains a heater system and a cooler that is cooled by means of the incoming fuel to the turbine combustors. The remainder of the system comprises pumps, level control system and oil delivery temperature control system. The return oil is pumped through a micro filter back to the reservoir tank.

A vibration pick-up is mounted on the gas generator casing flange, and it has a frequency range of 20-400cps. The signal is modified to read amplitude peak to peak and the system includes for alarm and trip points at preset levels.

Rolls Royce Olympus C Gas Generator Engine A (S/N 202205) has never been overhauled, and is currently in critical condition and not recommended to be run.  Damage to the HP Turbine blades has compromised the structural integrity of the unit, of which hot fired running comes with a significant risk of complete blade failure and subsequent catastrophic damage to the unit and downstream equipment.

A fibreoptic borescope inspection of one (1) combustor assembly in the 10:30 position was conducted on Gas Generator Engine A and revealed significant damage and corrosion and depletion of the blade exterior coatings.  Damage to three (3) HP turbine blades was observed and two blades showed evidence of material loss from the leading edge that was right through to the internal cooling air passage.  There is significant risk of catastrophic failure within the turbine if this engine is operated.  Otherwise, the Unit hot gas path general condition is commensurate with total operating time since new.  Inlet air system deficiencies, allowing particulate such as rust to form and be ingested by the engine, have resulted in significant abrasive damage to the Compressor first stage blades, inlet bullet-nose assembly and Compressor front frame inlet guide vanes.

The Gas Generator Engine A auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls also appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that the Engine A assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

Rolls Royce Olympus C Gas Generator Engine B (S/N 202223) was overhauled in 1993 and appears to be in good condition, above average for the time in service since last overhaul. Only minor exterior corrosion was noted, as well as minor depletion of the blade exterior coatings.

A fibreoptic borescope inspection of one (1) combustor assembly in the 10:30 position was conducted on Gas Generator Engine B and revealed no unserviceable conditions to all visible engine internal components. The inlet air bellmouth assembly is out of alignment and the resulting air turbulence will accelerate compressor blade root wear and will reduce power capacity by up to 500kW. Inlet air system deficiencies allowing particulate such as rust to form and be ingested by the engine have resulted in minor abrasive damage to the compressor first stage blades.

The Gas Generator Engine B auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls also appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that the Engine B assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

It is suggested that compressor washing be conducted every 6 months. Crank soak washing is recommended over fired wash. A recommended cleansing agent – B&B 3100 – should be diluted with distilled or de-ionized water. Distilled or de-ionized water should also be used for the follow-on rinse.

When removing a burner for borescope inspection, it was observed that one of the burners was off-center in the combustor can. The washers associated with the burners are discrete distance pieces to accommodate the difference between the casing and the actual combustion can such that the burner nozzle is at the center of the can. Incorrect installation of the washers when performing maintenance work will cause this problem. This off-center burner arrangement could contribute to the exhaust gas temperature variances that have resulted in numerous exhaust temperature spread alarms experienced at the site. It is also important that all combustor cans on an engine are the same model. Installing different models on the same engine could further contribute to the exhaust gas temperature variations. It is important that maintenance personnel are fully informed of correct burner assembly when doing maintenance work on the engines.

HYDRO provided a copy of Inspection Report prepared by ALBA POWER reflecting their more extensive borescope inspection work carried out on the Hardwoods Olympus C Engines in May

2007. We have included the ALBA Report in Appendix 4 as the ALBA observations and recommendations are similar to the conclusions arrived at in this Study. In addition, the ALBA photos clearly highlight the issues associated with each Engine.

### 5.2.2 Gas Generator/Power Turbines Auxiliaries

Some auxiliary system components are obsolete and are no longer supported by the manufacturer or have been supplanted by more modern equipment. These include:

- Ignition exciters
- Vibration monitoring system
- Speed governors/fuel valve assemblies.

Replacement auxiliary assemblies of current design are readily available however they do entail costs that need to be considered. HYDRO should decide on its requirement for plant availability so that alternative strategies of installing new systems versus holding a stock of spare parts on site can be compared.

Woodward Governors

The Woodward speed governors were observed to be in satisfactory condition. Spares for the governors are readily available.

Gas Generator Bearings

The major line bearings were not accessible in the time allotted for inspection. The gas generator engine line bearings (8) are of the rolling element type. Inspection of the magnetic chip detectors indicated satisfactory bearings condition.

Gas Generator Lube Oil System

The engine's lube oil supply/scavenge system is self contained and driven by the engine assembly. It appears to be in satisfactory condition. The oil is cooled by means of a heat exchanger that uses incoming fuel oil as a coolant for the engine lube oil.

Compressed Air System

The compressed air system is of standard design and appears to be in reasonable condition for a further 15 years of service however the exact same components may not be available for the coming 15 years. A single spare compressor for both sites is probably adequate to provide for continuous plant availability. There are two starting air compressors mounted on the auxiliary module in an enclosed room within the Auxiliary Module Building and two storage tanks for start-air located outside the Building. The system provides sufficient air for three engine starts. The two air-cooled compressors are rated to deliver air at a discharge pressure of 500 psig.

Each compressor contains an air inlet filter and silencers, and are driven by two 7-1/2 HP AC motors.

The two compressed air storage tanks (receivers) are sized to provide sufficient volume for at least three repeated starts of the gas generators. Relief valves are mounted on each tank to protect it from overpressure. Water traps are provided to automatically remove the condensed water from the bottom of each of the storage tanks. There is also a heating cable included in the drain circuits. The control system provides conventional start/stop control with lead/lag compressor selection. Compressor instrumentation appears to be in good working order.

Starter Motors

The starter motors have provided high reliability, but the model is no longer supported by Rolls Royce. It is suggested that a spare unit compatible with all four gas generators, should be carried by HYDRO. (The inventory of spare parts dated 2004, included one starter motor assembly).

### 5.2.3 Inlet Air Systems A & B

The original inlet air filter system at Hardwoods was redesigned in the early 2000's. The new filtering system consists of a monoclone pre-filter and a high efficiency second filter. This system is different than the inlet air filter system at Stephenville which still retains the original design. Refer to sub-section 6.2.3 for details on the Stephenville system.

The inlet air structures (Photo: HWD-002) are constructed of structural steel plate and framing supported by a cast-in-place concrete foundation. The concrete foundation was found to be in adequate condition and there were no visible cracks or deterioration noted. As well, no significant structural steel issues were noted during the inspection. The exterior coating was found to be in poor condition with surface corrosion and flaking of the coating noted in several locations over the exterior of both Air Inlet structures. Based on the condition of the existing coatings, we recommend that the Air Inlet structures be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-003).

There were several items noted during the inspection that require maintenance work. The interiors of inlet air plenums A and B show signs of advanced corrosion damage. Surface corrosion of the steel and flaking of the coating was noted inside the air inlet structures and is compromising the effectiveness of the air inlet filtering system (Photo: HWD-004). The basic structural integrity is good, and can be returned to satisfactory condition with basic sand blasting and replacement of the surface coatings on the interior of the air inlet plenum and silencers. The concrete slab on grade was found to be in acceptable condition.

Significant corrosion was also noted in the trough under the access doors for both air inlet structures. This corrosion is likely a result of water accumulation in the trough over extended

periods of time. We recommend that the following items be completed to repair this problem and help prevent it from reoccurring:

- Sand blast and coat all areas corroded under the access doors to the air inlet plenums (Photo: HWD-007).
- Weld new plates inside the troughs that will drain water to the centre of the trough.
- Drill a weep hole in the exterior of each air inlet structure to allow water to drain from the trough under the access doors.
- Replace the weather stripping on the access doors (Photo: HWD-006).
- Install a new drip cap over both access doors similar to the drip caps over the man doors on the gas generator/turbine modules and alternator modules (Photo: HWD-004).

Surface corrosion was also noted inside the filter enclosure at the top of both Air Inlet structures. We recommend that these interior spaces be cleaned, prepared and recoated when the exterior of the air inlet structures are recoated (Photo: HWD-005).

It was noted that the kick plates on the ends of the platform attached to the air inlet structure for Unit A are missing. This is in violation of fall protection regulations and should be repaired as soon as possible. During the site inspection, it was also noted that the ladders providing access to these platforms were quite narrow and did not flare out at the top. This made it quite difficult to exit and enter the ladder. We recommend that these ladders be replaced with new ladders that have proper widths at the top (Photos: HWD-008 & HWD-009).

The screens on the air inlet structure for Unit B were found to be highly corroded. These screens should be cleaned, prepared and recoated when the exterior of the air inlet structures are recoated (Photo: HWD-010).

In the case of Air Plenum A, there is evidence of silica sand, rust scale and small rocks in the inlet plenum, which eventually will be ingested by the turbine engine. It was noted that the second, inner row of rubber sealing strips is missing, allowing debris to enter the inlet plenum assembly from the basic structure “C” channel. In addition, impact damage to one of the inner silencer panels has torn the perforated sheet at that location.

In the case of Air Plenum B, there is evidence of silica sand and rust scale in the inlet plenum, which eventually will be ingested by the turbine engine. It was noted that the inlet bellmouth assembly on Engine B is not fitted correctly to the engine, causing inlet air turbulence and loss of efficiency. The assembly is out of alignment approximately 1.0 cm. creating significant turbulence to the inlet air stream. As the Engines during full power settings ingest over 240 Lbs/Sec. of air, the importance of correct bellmouth fitment cannot be overemphasized. Misalignment will create turbulence in this air stream, accelerating compressor blade root wear, and costing 500kW, or more of potential power output loss.

There is a misalignment between the attachment plate of the lifting beam and the air plenum structure that needs correction.

HYDRO staff should be made aware of the criticality of keeping the inlet air systems clean, and not allow small rocks and debris to remain in the systems following inspections and periodic maintenance. In the case of air inlet system A, the inner row of rubber sealing strips are deteriorated to the point of cracking and no longer making effective seals against unwanted air leaks.

### 5.2.4 Exhaust Stacks A & B

The exhaust stacks (Photo: HWD-002) for both power turbines are constructed of a heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stacks is constructed of heavy gauge steel plate. The exhaust stacks are supported by a cast in place concrete foundations. Based on information provided by N&L Hydro, these stacks were replaced in 1992. The interior silencer panels were reused. The snow doors on the exhaust stacks were modified from electric actuation to pneumatic operation in the mid 1980's. New expansion joints were installed in the stacks in 2004.

The foundation under the exhaust stacks was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. A grid of steel bars spans the area immediately above the engine exhaust the purpose was reported to be for preventing silencer panels from dropping and damaging the turbine, and also as a support for scaffolding for maintenance. Several of the internal grid bars retaining nuts have backed off to the inner end of the threads and should be re-tightened.

The light gauge exterior cladding on the upper portion of the exhaust stacks was found to be in poor condition. The cladding is very light gauge material with no corrugations. The cladding was generally warped and bent and could easily be deflected with light pressure, even from wind loads. Holes that appear to be pop rivet holes were noted in many locations on both exhaust stacks. Larger holes have also developed in the light gauge cladding in several locations as a result of corrosion. As well, the joints between panels of cladding are not sealed or lapped sufficiently to prevent water infiltration into the exhaust stack enclosure. These unsealed joints, large holes and the pop rivet holes allow a significant amount of moisture and water into the exhaust stack enclosures, which will lead to excess corrosion of the main structural elements and failure of the insulation. We therefore recommend that this cladding system be replaced with a new corrugated metal cladding system (Photos: HWD-011 & HWD-012)

The coating on the heavy gauge cladding on the lower portion of the exhaust stacks was also found to be in poor condition. Surface corrosion and coating failure was noted in several locations on both exhaust stacks. We recommend that this part of the exhaust stacks be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-013).

In the A exhaust stack, cracking is evident at two of the corners of the stack access door opening in the inner liner. As well, cracks in the inner liner were also noted directly below the door opening and in the internal rolled edge. These cracks are easily repaired and we recommend that repairs be completed at the next available opportunity (Photos: HWD-014 & 015 & 016). The remainder of the exhaust system appears to be in satisfactory condition.

The snow doors on the exhaust stack for Unit A were found to be in poor condition and in need of replacement. Significant corrosion was noted on the main structural members and the end of two (2) beams has completely corroded away. The snow doors on the exhaust stack for Unit B were also found to be in poor condition and in need of replacement. Significant corrosion was noted on the main structural members. We recommend that these doors be replaced within the next year given the level of deterioration in the structural steel members (Photos: HWD-020 & 021).

In the B exhaust stack, cracking is evident at the bottom edge of a lifting eye access hole on the internal rolled edge and at the upper two corners of the stack access door opening in the inner liner. Several cracks in the welds, which holding the interior mesh and insulation in place were also noted. Simple weld repairs will correct this cracking and should be carried out at the next available opportunity (Photos: HWD-017 7 018 & 019). The remainder of the exhaust system appears to be in satisfactory condition.

The doors providing access to the exhaust stacks are also in need of upgrades. The current door design is heavy and is not supported by hinges and is simple bolted in place. Therefore it is difficult and time consuming for staff to remove the doors. As well, there are no drip caps over the doors and the seals are inadequate. These doors are therefore leaking and causing corrosion in the exhaust stacks and gas turbine enclosures below. The doors should be reworked so they are on hinges, have drip caps and have proper seals to make them weather tight. The hatches below these doors in the roof of the gas turbine enclosure must also be modified to prevent water leaks when these exhaust stack doors are modified (Photo: HWD-022).

During the site inspection it was also noted that the ladders providing access to the platform on the exhaust stacks were quite narrow and did not flare out at the top. This made it quite difficult to exit and enter the ladder. We recommend that these ladders be replaced with new ladders that have proper widths at the top (Photo: HWD-008).

### 5.2.5 Curtiss Wright Power Turbines

There are two Curtiss Wright Power Turbines A and B. Each Curtiss Wright power turbine is a two-stage axial flow unit with the rotor assembly and main shaft supported as a cantilever by two white metal bearings housed in a pedestal. The power turbine unit is connected to the gas generator by a gas duct incorporating a bellows joint. The gas generators receives ambient air from the air inlet plenums and delivers high temperature and pressure gas to the power turbines

which converts the thermal energy into rotating mechanical power. The power turbines output shaft is coupled to the alternator through SSS clutches.

The two-stage axial flow rotor consists of two rows of cast Stellite 31 blades. The blades are attached to a forged 422 stainless steel disc; the blades are secured to the disc by fir tree root fixings. The rotor assembly consists of a front labyrinth ring, first stage blade and disc assembly, spool spacer, interstage labyrinth, second stage blade and disc assembly and the main shaft. The components are fixed to the main shaft by tie bolts. A diagram (figure 2-58) illustrating the power turbine assembly is included in Appendix 4.

The oil supply to the power turbine is supplied from the alternator module and provides lubrication to the front and rear main radial bearings and the thrust bearing.

The stator casing was originally made of austenitic nodular cast iron alloy, split on the horizontal centre-line to facilitate access to the stator vanes and the rotor. The casings however were prone to severe cracking resulting in a de-rating of the gas turbine for a number of years. In the 1980's new casings were designed, manufactured and installed on both gas turbines. The new casings used an incanol alloy that is less prone to cracking. There have been opportunities to inspect the blading of end B at Hardwoods when the gas generator was removed for extensive overhaul in1993. The Curtiss Wright Power turbines A&B have provided excellent service since the major modifications to the casings. There have been no records of significant problems noted or significant work carried out on the power turbines over the past 12 years other than a requirement to re-balance the A Power Turbine at Hardwoods in 1995.

The elements that could impact on the reliability and availability of the Power Turbines are the blades, discs, bearings, and vibration characteristics. These are somewhat inter-related with uneven deterioration of the blades leading to degradation of bearings and vibration characteristics.

Access to the exhaust stacks internals, during the site visit, allowed viewing of the Deflector Rings, Second Stage Power Turbine Blades and Second Stage Power Turbine Nozzles on both Power Turbines A and B. No unserviceable conditions were noted, and all visible components appear to be in a condition above average for the total time since installation and run hours.

From our review of operations of the Hardwoods Facility particularly the minimal running time on the power turbines and our visual examination during the site visit, there is no expectation that the Power Turbines performance will change significantly during the next fifteen years. We recommend however that upon removal of the Gas Generator Engine assemblies as noted in sub-section 5.2.1, the Curtiss Wright power turbine assemblies should be inspected in detail to verify the mechanical integrity of the units. In order of priority the following points are recommended to be inspected/ refurbished:

- Main line bearings to be removed and inspected;

- Turbine blades to be removed and metallurgical sampling done to verify alloy composition, as well as check wear to the blade roots;
- Turbine disks to be removed and metallurgical sampling done to verify alloy composition and creep growth.

More modern and effective anti-corrosion/thermal protection coatings are available, and are recommended to be applied to the power turbine blades and nozzles to give superior protection/reliability for future operation.

### 5.2.6 SSS Power Turbine Clutches A & B

The SSS Clutch is designed for use between a turbine and an alternator to primarily engage and disengage the gas turbine from the alternator when the alternator operates as a synchronous condenser. When operating for generation purposes the clutch will remain engaged with the alternator. In the case of synchronous condenser operation, the clutch can automatically connect the turbine to the alternator at any speed, with engagement occurring immediately when the turbine speed exceeds that of the alternator. The design accommodates changes in the alignment of the gas turbine and alternator shafts to allow for thermal expansion effects. It acts as a double toothed flexible coupling with tooth surfaces that are designed for low stress and are hardened by nitriding. The clutch is lubricated by oil catchers on the input and output shafts. A dashpot system provides oil to maintain clutch engagement in the event of a reduction of turbine power to the idling mode.

The Power Turbine Clutches A and B were not accessible in the time allotted for inspection during the site visit. A review of available operational history indicates that most problems associated with the clutch assembly have originated with the various sub-systems such as – position indication, brake function and shifting mechanism. All other history indicates satisfactory operation of the clutch assembly itself.

During the site visit on August 21, 2007, when attempting to startup Engine A, and engage it with the rotating alternator (synchronous condenser mode), both the Alternator & Engine A tripped. Indication was that the clutch had not engaged within a prescribed time, resulting in the trip. Following a post mortem conducted by HYDRO it was determined that the clutch had actually engaged, however in doing so, the cover of the clutch proximity switch had been ripped off, while the clutch was engaging, causing the switch to malfunction and send an erroneous signal to the DCS system. There appears to be a physical interference problem with the proximity switch when the clutch engages. HYDRO noted this problem has occurred before on both engines however more frequently on the A end than the B end of the Gas Turbine.

A Report by Maxwell Reid on alternator refurbishment work carried out in 1995 (refer to sub-section 5.3.4 for further details) also noted that the clutch cover, fabricated at the time by Mercer's Machine Shop, was found to be too long and needed further work. It was also found that the proximity switch on the "A" end clutch was mounted too close to the ring on the clutch cover fabricated by Mercer's. Since there are still problems with mechanical interference

between the clutch engagement and the proximity switch on the “A” end clutch, we recommend that HYDRO investigate the clutch assembly to determine if current interference problem between the clutch and the proximity switch is somehow related to the work done in 1995.

There has been no reported significant work carried out on the Clutches over the past 12 years. The clutch system itself has provided good service and should continue to do so for the next 15 years. There have been a number of problems with the auxiliaries such as the hydraulic system and the position monitoring. These have resulted in difficulties to clutch operations when synchronizing the power turbine with the spinning alternator. It is advised that the components comprising the auxiliaries to the clutches be reviewed for potential replacement with currently available and proven reliability components.

It is recommended that when the gas generator engines have been removed for refurbishment the drive clutches be completely disassembled and inspected. No major structural problems are anticipated; however the brake, position indication and actuation systems should be refurbished and tested to achieve continued reliable operation. It may be prudent to place spare internal components into inventory, as the availability of such parts into the future are unknown and may be cause for concern.

### 5.2.7 Main Power Train Bearings

The Main Power Train bearings support the power turbines, clutches, and the alternator/exciter. They are of the journal, pressure lubricated type, but they were not accessible in the time allotted for inspections. Review of oil sampling results with operational staff indicated no anticipated problems with these bearing assemblies. However it was noted that the unit vibrations were pronounced at the A assembly end and this could be caused by a defect in the bearing at that end.

Significant ground and background vibration is evident while the alternator is operating in synchronous condenser mode. The non-exciter end bearing location specifically appears to be the source of the vibration and a trim balance is recommended to be performed at the earliest opportunity to bring this vibration down to lower levels. The station vibration monitoring equipment shows the non-exciter end of the generator to have four (4) times higher residual imbalance than the exciter end. This vibration is exciting much of the package hardware and will contribute to metal component fatigue, and possible shortening of the gas generators’ rolling element bearings.

### 5.2.8 Main Lube Oil System

The main lube system is a closed loop that incorporates a tank that is partitioned internally to allow for entrained gas (air) in the return to evacuate. The tank is large enough to store and maintain oil temperature. Oil is delivered under pressure to the power turbine, clutches and

alternator and is returned to the tank by gravity and negative pressure generated by a vacuum fan on the tank.

The oil is moved and pressurized by the lube oil pumps located in the Auxiliary Module Building. Constant pressure is maintained in the discharge header by means of a regulating valve which establishes a header discharge pressure of 30 psi (2.04 bars) by sensing discharge pressure after the cooler and filters. The pumps are protected by a relief valve which is set at 100 psi (6.8 bars) and will bypass lube oil in the event of system blockage.

The power turbines, clutches and alternator low pressure lube oil system proper all appear to be in satisfactory condition. The high pressure rotor jacking oil system also appears to be in satisfactory condition.

From the lube oil pumps, the oil flows to an oil/water-glycol cooler. The cooler is a shell and tube type heat exchanger with internal baffles that allows a heat exchange from the oil to the coolant glycol, which is actually a glycol - water solution.

The glycol coolant from the main lube oil cooler is circulated by pumping through a 3-way valve that controls the quantity re-circulated back to the oil-cooler or to the glycol/air heat exchanger (glycol-cooler). As the main lube oil delivered from the oil tank gets warmer, the 3-way valve will operate under the control of its capillary, and will slowly restrict the re-circulating glycol coolant such that the coolant has to pass through the external glycol/air heat exchanger and then back via the 3-way valve where it is mixed with the warmer coolant still circulating, and then to the main lube oil cooler. In this manner, the 3-way valve controls the flows in the coolant sections of the heat exchangers to maintain a steady delivery temperature of oil to the bearings.

The main lube oil system electrical, mechanical and instrumentation equipment is generally in good condition but if certain components such as pumps or fans fail completely, it may be difficult to find the identical item for replacement. The necessary precaution would be to acquire spares for HYDRO to stock. This is particularly relevant to the single glycol circulating pump and the three-way valve, because the power plant will be unavailable for operation in the absence of these components. HYDRO should decide on its requirement for plant availability so that the alternative strategies of installing a back-up pump or valve versus holding a spare pump/valve on site can be compared. (Some replacement parts were identified in the spare parts inventory 2004, for a glycol pump. It is not clear whether the pump associated with the spare parts is the Main Lube Oil Cooling System, or for the Alternator Cooling System at Stephenville).

### 5.2.9 Glycol Cooler for Main Lube Oil Cooling System

The external glycol heat exchanger (Photo: HWD-023) is of the finned tube air blast type with its electrically-driven cooling fans and the coolant circulating pump controlled by a sequencer. The main lube oil external glycol cooler assembly is in satisfactory physical condition.

It is our understanding that maintenance work was completed on the existing glycol heat exchanger last year. This work included the replacement of the bottom section of the heat exchanger and other minor repairs. A visual inspection of the new and old steel structure was carried out and all steel members were found to be in satisfactory condition. However, it was noted that the coating on the older structural steel members and canopy was failing. Surface corrosion and flaking of the coating was noted in several locations. We, therefore, recommend that the entire steel structure and associated cladding be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-024).

### 5.2.10 Gas Generator/Turbines Enclosures A & B

The gas generator/turbine modules are constructed of structural steel framing with steel plate exterior cladding. The exterior coating was found to be in poor condition with surface corrosion and coatings failure noted in several locations. We recommend that the exterior of both gas turbine enclosures be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-025). The roofs of the gas turbine enclosures are not sloped and water ponds on the roofs in places. This is contributing to the coatings failure and corrosion of the roof steel. The concrete foundation under the gas generator/turbine modules was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

A visual inspection of the gas generator/turbine module supports and welds was carried out and no issues were noted. A visual inspection of the exposed steel structure inside the gas turbines modules was also completed. It was noted that there were some areas in which surface corrosion was present on structural members. Water is also entering the gas turbine enclosure from the exhaust stack doors above. These doors should be modified to make them weather tight prior to recoating the gas turbine enclosures and exhaust stacks. These areas were generally small and the corrosion mild and therefore are not a significant concern at this time. However, if this facility is to remain in operation for the next 15 years, the next time the gas turbine equipment is removed for maintenance, we recommend that the interior of the gas generator/turbine modules be cleaned, areas with corrosion sandblasted and the interior of the modules be recoated (Photo: HWD-026).

The existing man doors in the gas turbine modules do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow Hydro site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the gas generator/turbine modules.

### 5.2.11 Fire Detection and Protection

The fire suppression system consists of Inergen systems located in (i) the turbine enclosure (Modules A and B), (ii) the alternator enclosure (Clutch A and B compartments) (iii) in the fuel unloading building, (iv) in the fuel forwarding building, (iv) the auxiliary module building and (v) the control building. There are heat and smoke detectors located at each location. The Inergen

fire suppression systems are in excellent condition and available for service for an additional 15 years.

### 5.2.12 Gas Generator/Turbine Spares

An observation made during the visit to Hardwoods, and during inspection of the available outage/maintenance reports provided, is that if additional spare parts inventories were held on-site, the overall reliability of the package could be enhanced. Recommended Gas Generator Engine spares include:

- Fuel injection nozzles: A majority of unscheduled shut downs are caused by high exhaust gas temperature deviation. A spare set of flow balanced fuel injection nozzles would allow mechanical staff to replace defective nozzles with serviceable units, to bring total temperature deviation to within acceptable limits.

- Starter assembly: These units are no longer available from the original manufacturer, and are understandably critical to the operation of the package. A spare starter assembly would enhance current and future reliability.

- Glycol Circulation Pump

- Three-way Glycol Mixing Valve

There are companies that hold spare parts and complete gas generators in anticipation of future requirements. We recommend a strategy whereby HYDRO can set up a system of quick replacement if needed. It is unlikely that both gas generators will become unserviceable simultaneously allowing the alternator to be operated as a synchronous condenser or at 50% MW output on one or other gas generator.

## 5.3 ALTERNATOR/EXCITATION SYSTEM

### 5.3.1 Alternator Description

The Hardwoods Alternator and Excitation System were manufactured by the Brush Electrical Machines Ltd. of England in 1976. The Alternator was designed to ANSI Specification C50-13. The 13,800 volt, 3 phase 3600 rpm Alternator is an air cooled machine rated at 63,340 KVA at a 0.85 power factor. The Alternator utilizes a rotating brushless type exciter mounted on a stub to the main rotating shaft.

The Alternator cooling consists of an air supply system that includes a baffle system for cyclonic separation of particles, followed by a micro filter system. The clean air is induced into the alternator by fan blades mounted on the alternator main shaft, and is rejected from the system via exhaust louvers.

The Alternator/Exciter System is contained in a weatherproof, walk-in sound insulated enclosure. The stator is fastened to the enclosure bedplate. The Alternator is enclosed with two end canopies (bulkheads) and a top section canopy. Each canopy is accessible via doors. The alternator enclosure is protected by an Inergen fire suppression system. Refer to sub-section 5.3.7 for further details on the Alternator/Exciter enclosure.

The alternator's inner stator frame is fabricated from structural steel, welded together to form a rigid structure. The stator core consists of low loss, silicone steel segmental stampings insulated by a layer of varnish on both sides of each lamination. The core is divided into short sections by radial ventilating ducts. The core is bolted to the stator frame. The stator copper winding is of the two layer diamond type with the coils held in open slots by epoxy paper laminate wedges. The two coil layers are separated by epoxy paper laminate wedges. The insulation is Class B synthetic resin bonded mica glass tape. The stator winding laminations are transposed in a regular pattern to minimize circulating currents and losses. The coils are protected against corona formation by coating in the slot length with conducting (graphite) paint and with corona relief paint at each end of the core. The end winding coils are braced with glass cord and densified epoxy paper laminate blocks and supported from the core ends by insulated brackets.

The stator line and neutral terminals are brought out to a cubicle containing the line and neutral bushings. The line bushings are connected to a metal enclosed bus duct system. The Alternator neutral is grounded via a grounding transformer and resistor (refer to section 5.5 for further details on the bus duct, the alternator circuit breaker and neutral grounding).

The rotor consists of a solid carbon steel forging carried in two bearings with a shrunk on half coupling. The field windings are located in slots milled into the rotor forging. The windings are held in place by steel and bronze wedges. Intertooth slots are milled to provide a longitudinal air passage for the cooling air. The windings consist of multi-turn copper coils insulated throughout with Class F mica. The end windings are supported by non-magnetic end caps shrunk on to a spigot on the rotor body and braced with resin bonded asbestos fabric packing blocks and boxed in with a steel end bracket. The material used in the end caps could not be determined from a review of available documentation. Early end caps used 18%Mn / 4%Cr non-magnetic material whereas more current designs use 18%Mn / 18%Cr. The former is susceptible to stress-corrosion cracking. It is recommended that the end caps be closely examined during the refurbishment project.

The alternator and exciter bearings (3) are carried in a fabricated steel pedestal. The housing is split horizontally on the shaft centerline. The bearing is white metal lined and spherically seated. Bearings are lubricated by pressurized oil at 20/30 psig (refer to sub-sections 5.2.7 and 5.2.8 for further details). The oil drain systems operate below atmospheric resulting in air being drawn in through the labyrinth seals providing the necessary ventilation. A high pressure jacking oil system is provided for start-up and shut down purposes.

The stator winding temperature is measured by embedded resistance temperature detectors (RTD's) distributed throughout the windings in the slots. There are 4 RTDs per phase. Alternator air temperatures are measured by thermocouples fitted in the air outlets and inlets from the stator as well as the exciter air outlet. The temperature of the drain oil in each pedestal bearing is measured by an immersed thermocouple. A vibration detector is mounted on the pedestal of each rotor bearing and on the exciter bearing pedestal.

### 5.3.2 Excitation System Description

The main exciter is of the rotating brushless type mounted on a stub shaft which forms an extension of the main drive shaft at one end of the machine and is supported by a third bearing. The brushless exciter was designed to ANSI Specification C50-13. The excitation volts are 36.0 volts dc. The exciter has stationary field coils and a rotating armature. The exciter field windings are on the stator and its armature is on the rotor. The AC output from the exciter armature is fed through a set of diodes that are also mounted on the rotor to produce a DC voltage. This is fed directly to the field windings of the main alternator which are also located on the rotor. The excitation control system consists of a "Normal" and "Standby" automatic voltage regulator (AVR) backed up by a "Manual" control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings. The Hardwoods Gas Turbine utilizes the original brushless exciter system provided in 1976. The original excitation AVR control system at Hardwoods was replaced in 2006.

### 5.3.3 Alternator/Excitation General Assessment

As noted previously, the configuration of the Hardwoods Gas Turbine includes two engines, two power turbines and only one Alternator. This makes the Alternator a critical component in the availability and reliability of the Gas Turbine. An Alternator problem therefore can result in major outages.

While HYDRO personnel have indicated the Alternator and Exciter have generally provided good reliable service at Hardwoods, the actual condition of the stator, rotor, exciter and auxiliary components is unknown. HYDRO was not able to provide documentation, during the Study, outlining a history of Alternator and Exciter condition testing on this equipment ie data from electrical tests and inspections carried out on the equipment over the years. In order to properly assess the present condition and life expectancy of the Alternator and Exciter, it is very important that data from such tests and inspections if carried out on the equipment over its years of operation be current and available for review. Unfortunately, this information was not available. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Since this information was not available, such an assessment was not able to be carried out in the Study.

With the type of operation the Alternator has been subjected to over the years – frequent stop/starts and synchronous condenser mode operation (refer to sub-section 2.1) - expectations

are that the stator core, stator and rotor windings/insulation, rotor retaining rings and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years. In addition, as discussed in sub-section 5.3.4, the rotor at Hardwoods has had significant refurbishment work carried out in the past. Typical alternator stator and rotor problems that can develop over time from such operation can include:

Potential Alternator Stator Problems

- Stator winding insulation integrity and cracking
- Stator windings -- bar movement, sparking, bulging or puffy coils
- Stator end windings – bar movement, loose/broken bracing and ties, corona (arcing) activity
- Stator wedges – looseness, sparking damage
- Stator core insulation – hot spots. Shorting or low resistances in the inter-laminar insulation may result in abnormal currents, localized heating and iron damage.
- Cracked connections
- Contamination

Potential Alternator Rotor Problems

- Shorted turns and field grounds – occurs when the insulation in the field is damaged. There are a number of factors that can lead to field insulation breakdown/degradation – (i) length of time the alternator has been in service (ii) mode of operation – frequent start-stops (thermal cycling) or base load operation and (iii) contamination introduced into the machine
- Rotor wedges -- looseness, sparking damage
- Thermal sensitivity – is a term used to describe an excessive vibration of the rotor induced by the heating effect of the field current. As field current flows, the copper winding heats up and having a greater coefficient of thermal expansion, expands more than the steel forging. The disparity in expansion transmits forces to the forging through the rotor slots, wedges and retaining rings. The heat generated in this manner is normally drawn away by the cooling medium (air). Problems can occur when the winding forces act unevenly or when a temperature differential exists across the rotor due to blocked ventilation. These events will cause the rotor to bow somewhat resulting in an imbalance and subsequent vibration.
- Negative sequence events -- operating incidents (closing the alternator breaker when at standstill; single phase operation; transients, etc) that induce heating, arcing within the alternator
- Contamination – problems that arise from contamination buildup on the rotor include low megger readings, overheating and creepage failures

- Forging/retaining ring damage – rotor forgings over time can develop cracking or burning caused by extraordinary events such as negative sequence currents flowing in the forging. Retaining rings are the highest stressed components of the alternator. Alternators operating in cycling modes that require frequent start-stops are susceptible to rotor tooth top cracking. It is generally recommended that rotors that have been in service in excess of 25 years with approximately 5000 start-stops should be inspected for damage.

In the absence of electrical testing and inspection records on the Alternator over its 30 years of service, it is difficult to determine if any of the potential problems listed above currently exist or might occur in the next 15 year period. In order to determine the present condition of the Alternator and Exciter, the following recommendations are proposed:

- A series of electrical tests in line with sub-section 5.3.5 be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above and in order to determine what specific refurbishment work might be necessary on the Alternator in particular, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.

### 5.3.4 Alternator/Excitation Operational and Maintenance Issues

The preceding sub-section listed potential alternator stator and rotor problems that can develop over time. This sub-section will outline problems noted by HYDRO personnel and refurbishment work carried out on the alternator in the past.

There are reported incidents of vibration alarms occurring on the exciter end of the Alternator on start-up. The reason for or cause of the vibration alarm has not been identified to date. This alarm could be caused by a number of factors:

- faulty vibration detector,
- shorted turns in a field coil,
- rotor balance issue,
- shaft alignment issue, or
- bearing issues.

Two Reports were provided by HYDRO on significant maintenance/refurbishment work carried out on the Hardwoods Alternator in 1983 and 1995.

- In 1983, after only 6 -7 years of operation, rotor earth faults caused significant damage to the rotor insulation primarily at the exciter end beneath the rotor end cap. The indicator of this problem was a trip of the Gas Turbine due to high vibration during synchronous operation. The repair procedure involved pulling the rotor from the stator and removing the rotor end caps to repair the fault. In fact, the under cap insulation on both ends of the rotor were brought in line with the current Brush rotor insulation at the time. The rotor fan and balance ring were also replaced. The rotor was demagnetized and realigned in the stator. (Reference: Report by Arden Turpin of Engineering Services dated September 21, 1983.)

- In 1995, further work was carried out on the rotor. At that time, the rotor was re-wedged and taped. A Brush Report on the details of the work carried out was not provided, however there is a reference to this work in a FERN Engineering Inc Report No. 5444-08-2 dated September 27, 1995 and further reference in a Report prepared by Maxwell Reid, Acting GT Electrical Operator in August 1995.

  Following the work carried out by Brush and re-assembly of the Alternator, high vibration was noted at the “A” end of the Gas Turbine. The FERN work found the rotor to be unbalanced at both ends. The rotor was balanced. In addition, the “A” end power turbine was also successfully balanced. It was noted in the Fern Report that the power turbine high vibrations occurred at the rear bearing (clutch end) and this bearing has a tendency to be unstable because of its light loading. The instability is more noticeable at low power levels.

  The Maxwell Reid Report also noted that the clutch cover, fabricated at the time by Mercer’s Machine Shop, was found to be too long and needed further work. It was also found that the proximity switch on the “A” end clutch was mounted too close to the ring on the clutch cover fabricated by Mercer’s. There are still problems with mechanical interference between the clutch engagement and the proximity switch (refer to sub-section 5.2.6 for further details).

These Reports indicate that significant work was carried out on the rotor over the years. There is no reported significant work carried out on the alternator over the past 12 years. Whether the significant work carried out on the Rotor in the past will be a factor in the future cannot be determined quantitatively or qualitatively without a further thorough examination of the rotor to assess its current condition.

The original excitation AVR control system at Hardwoods was replaced in 2006 with an ABB DCS 500 Unitrol F Series System type AFT-O/C1F1-F63. The new AVR control system is reported by HYDRO as performing well since installation.

### 5.3.5 Alternator/Excitation Testing Program

In order to assess the condition and life expectancy of the Alternator and its Excitation System, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad.

The following types of electrical tests are often carried out on an alternator and excitation system as part of ongoing inspection and maintenance programs:

Stator Electrical Tests

- EL-CID tests --- detects problems in the stator core especially inter-laminar insulation defects (hot spots)
- Partial Discharge Test --- detects stator winding insulation deterioration
- Polarization Index Test --- tests the insulation resistance to ground
- Hi-Pot Tests --- Insulation test
- Megger Tests at 1000 or 5000 V DC
- Thermocouple tests/calibrations
- Inspection and tests of Alternator bushings

Rotor Electrical Tests

- Megger Tests at 500 V DC -- detects rotor winding insulation deterioration / contamination
- Rotor winding resistance measurements

Bearings Electrical Tests

- Megger tests to indicate general cleanliness of bearing pedestal and insulation resistance
- Thermocouple tests/calibrations

Excitation System Electrical and Operational Tests

- Exciter rotor and stator winding resistance measurements
- Polarization Index measurements and Megger tests to determine condition of the exciter rotor and stator winding insulation
- Thermocouple tests/calibrations
- Diode checks - measurement of diode forward and reverse bias resistance and voltage drop; resistance of fuses; etc
- Operational checks on the AVR

The following Alternator visual inspections are often carried out as part of ongoing inspection and maintenance programs. These inspections, carried out during major outages with the Alternator removed from the Unit, can assess the condition of the stator, rotor and bearings. Items typically inspected during major outages are as follows:

Stator Visual Inspection

- Loose or damaged wedges;
- Loose or cracked or failed connectors;
- Dusting, greasing and other signs of movement of windings;
- Indication of arcing (hot spots); damaged laminations;
- Loose Core bolts;
- Signs of contamination / excessive dirt

Rotor Visual Inspection

- Signs of physical damage;
- Loose or cracked or failed connectors;
- Slot wedge migration and possible contact with retaining ring;
- Signs of overheating;
- Loose rotor wedges;
- Dye penetrant examinations and magnetic particle tests on forgings, retaining rings and fan components to detect fatigue cracks; ultrasonic examination of interior surfaces of the forging and retaining rings

Bearings Visual Inspection

- Assess general condition of the bearings
- Do the bearings require re-babbiting or machining?

HYDRO provided copies of its Gas Turbine daily, weekly, semi-annual, annual and 5 year inspection check lists as well as the 6 year P&C inspection check list. Most of these inspection check lists were dated 2003. There is essentially no reference to alternator and exciter tests or inspections on these lists. Copies of these lists are included in Appendix 5. In addition there are Alternator and Exciter tests and inspections listed in the O&M Manuals for each site. It is not obvious that any of these recommended tests and inspections is being carried out by HYDRO.

On a go-forward basis, it is recommended that a regular formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the above listed tests and inspections are part of that program. The electrical tests should be conducted on an annual basis with major visual inspections on a 5 year basis. The test data and inspection information should be recorded and stored at a central location for easy access in the future. In addition, a specific group at HYDRO should be charged with the responsibility for conducting such tests and inspections.

### 5.3.6 Alternator/Excitation Recommendations Summary

- It is recommended that a series of electrical tests be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.

- In addition to the electrical tests noted above, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.
- The Curtiss-Wright Turbine-Alternator Manual (Book 3) recommends a minimum list of spare parts that should be carried for the Alternator and its Excitation System. It is recommended that the suggested list of spares be stocked at one central location for both the Hardwoods and Stephenville sites.
- On a go-forward basis, it is recommended that a regular (annually; semi-annually; etc) formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the tests and inspections listed in sub-section 5.3.5 be part of that program.

### 5.3.7 Alternator/Exciter Enclosure

The alternator module is constructed of structural steel framing with a steel plate exterior cladding. The exterior coating was found to be in poor condition. Surface corrosion and flaking of the coating were noted in several locations on the exterior of the enclosure. We recommend that the exterior of the alternator enclosure be cleaned, prepared and recoated within the next two (2) years (Photo: HWD-027). The concrete foundation under the generator module was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. During the site inspection the alternator was operating in as a synchronous condenser. Therefore we were not able to carry out a visual inspection of the interior of the module.

The existing man doors in the alternator module do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow HYDRO site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the alternator module.

## 5.4 FUEL OIL SYSTEM

### 5.4.1 Fuel Unloading and Storage

The Gas Generator Engine fuel is No. 2 diesel oil which is delivered to the Site by truck. Fuel storage comprises one storage tank with 14,000 bbl nominal capacity (2,225,000 litres) (Photo: HWD-028). At 50 MW, the plant will use about 16,000 L/hour, so one tank-full lasts approximately 5.5 days. The tank contained oil at the time of inspection, so only visual inspection of the exterior was carried out.

A fuel storage tank farm upgrade was carried out in 1996/97. Originally there were two tanks at the Hardwoods facility. During the upgrade, one tank was completely removed; the remaining

tank was cleaned, repairs were carried out and the interior floor was recoated. The containment dyke was also modified as part of this upgrade project. A new section of dyke was added to reduce the size of the original containment area and the dyke was reshaped to meet the regulations for spill containment at the time. The existing tank was also lifted at this time and a new dyke liner was installed throughout the entire containment area. The existing tank exterior was recoated in 2000. One storage tank may present logistical problems related to temporary fuel supply when the single tank has to be drained for internal inspection in the future.

The tank was built to API Standard 650, and should be operated subject to API Standard 653 – Tank Inspection, Repair, Alteration and Reconstruction. This standard calls for periodic inspections and records of construction, inspections, and repairs. The frequency of inspections can be linked to a rate of corrosion or in the absence of measurements; the frequency of inspection must be less than every ten years.

No records, as required by API 653, have been provided by HYDRO to date. We recommend that HYDRO confirm that inspections have been carried out and inspections are properly documented. The tank has been in service since the up-grade in 1997. At that time, an internal inspection and checks on metal thickness should have been carried out and documented on file. From an external observation, the tank appears to be in generally good condition and should be serviceable for a further 15 years use.

The exterior coating of the fuel storage tank was found to be well faded and in marginal condition. In several locations surface corrosion and spot failures of the coating were noted. Peeling of the coating was also noted on the roof of the tank. Coating failure and corrosion was most notable on the stairs and handrail on the tank. Given the size and number of coating failures this is not an immediate concern. However, the exterior of the tank will like require recoating within the next five (5) to seven (7) years (Photos: HWD-029 & 030). However, the stairs and handrail will like require recoating within the next two (2) to three (3) years based on the current level of corrosion (Photo: HWD-031).

During the inspection it was noted that two of the stair treads on the tank were badly corroded and in need of replacement. As well, the hand rail on the top of the tank does not have a kickplate installed. Since these issues are safety related they should be addressed at the earliest opportunity. It was also noted during the site inspection that there was no grounding installed on this fuel storage tank.

The storage tank is fitted with a float and tape level gauge, a conductivity level switch, a differential pressure level transmitter, a temperature gauge. All instrumentation equipment appears to be in good working order.

The fuel oil containment dyke was found to be in generally good condition at the time of inspection. The dyke walls were found to be in good condition with adequate gravel and good grading. The containment dyke area was well lit with four (4) light standards and there was an

eight foot high chain link fence surrounding the area that was in good condition. The bottom of the tank is elevated above the bottom of the dyke to prevent submergence in water and premature corrosion of the tank bottom.

It was noted that there was water in the containment dyke during the inspection. Hydro site personnel indicated that the water was removed from the dyke by placing a submersible pump inside the dyke and pumping it as required. HYDRO may wish to consider installing a sump, gravity feed drain pipe and manually operated valve to allow easier and more frequent draining of the containment dyke.

### 5.4.2 Fuel Forwarding

The function of the fuel forwarding module is to provide fuel at a positive and constant pressure to the gas generator engines for combustion. An inspection was made of the fuel forwarding equipment contained in a building adjacent to the Gas Turbine. The major equipment located inside the building consisted of the main pump and motor, the auxiliary fuel pump and motor, the electric fuel heater, fuel filters, pressure switches, control valves, regulator valve and the associated piping.

The pumps, valves and piping were checked for evidence of problems. Nothing significant was found and the equipment had a well cared for appearance. There is sufficient back-up pumping and valves to provide a low risk of failure to deliver fuel. However, there is only one fuel heater and a spare replacement element should be carried together with the necessary gaskets, etc. Nothing of this nature was noted in the inventory of spare parts.

All instrumentation appears to be in good working order.

### 5.4.3 Fuel Piping

The piping from the fuel unloading building to the storage tank is above ground. The condition of the piping system is good and should be reliable for a further 15 years of service.

The piping from the fuel storage tank to the fuel forwarding building is a combination of aboveground/underground and does not conform to current codes. HYDRO is currently replacing the underground sections of the piping with double-walled piping with vacuum monitoring. The interior pipe is 4 inch and the exterior pipe is 6 inch.

The piping from the fuel forwarding facility to the power plant is above ground and in cold weather the fuel temperature can be a problem for successful start-up. HYDRO personnel stated that they are planning to consider a properly-designed fuel temperature control system or electrically heat trace the above ground piping in 2007.

## 5.5 ELECTRICAL SYSTEMS

### 5.5.1 13.8kV Switchgear

The switchgear serves to isolate the plant and its related systems electrically from the grid when it is not running or is down for maintenance. The switchgear and associated protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions.

Switchgear is subject to deterioration over time due to breaker contact wear, arcing damage and insulation breakdown. A typical switchgear installation includes integral instrumentation transformers, which are also subject to insulation degradation. While generator breakers are infrequently called upon to interrupt heavy or short-circuit loads, the recommendations of the manufacturer should be followed with respect to inspections and maintenance schedules.

Switchgear should be replaced when no longer supported by the manufacturer, parts availability wanes and safety of personnel or equipment potentially becomes compromised as a result.

The 15 KV 3000A metal-clad walk-in switchgear assembly houses the 13.8 KV alternator circuit breaker, potential and current transformers, and the 600V breakers for the station transformer. The alternator breaker is a withdrawable magnetic air type circuit breaker manufactured by Westinghouse. HYDRO provided a copy of a report on a condition assessment of the Hardwoods and Stephenville 15 kV Switchgear and outdoor Bus Duct carried out by Acres in 1995. It is our understanding that most of the recommendations outlined in that report have been carried out. There was a budget proposal in 1998 to replace the alternator circuit breaker and use the existing beaker as a system spare to serve both the Stephenville and Hardwoods site. According to the Hardwood site operator, the breaker was never replaced and it is the original installation at 1976. While a detailed inspection of the switchgear was not carried out in this study, the physical condition of the switchgear and the associated equipment appears to be in good condition. With the age of the breaker, it is recommended a thorough inspection and a complete over-hauled of the breaker should be carried out as soon as it is amiable. It may be prudent to consider replacing the existing breaker with a vacuum-type circuit breaker because it could be difficult to purchase direct replacement parts for magnetic air type circuit breakers. In addition, vacuum breakers require less maintenance.

The Cable entrance cubical for the switchgear is in a state of mess. The 600V power cable is mixed with the control and instrumentation cables. The only separation between the cables and the 600V power terminals is the plastic cover on the 600V terminals. Besides looking untidy, it is creating a safety hazard. For a temporary fix, it is suggested that dividers to be installed to separate the power cables from the control and instrumentation cables. Good house keeping should be applied to tidy up the control and instrument cables. For a long term solution, the power cable should be installed in a separate compartment from the control and instrumentation cables. If there is any sign of insulation deterioration, the cable should be replaced. Any

conductor terminated into a spring type termination block should have a ferrule installed at the wire end to align with the terminal block. There were comments from the P&C electrician about DC Ground alarms. The DC ground may be caused by the insulation deterioration of the control and instrumentation cable or improper termination of the conductors. It would be impractical to replace all the control and instrumentation cables at one time but if there is a chance of replacing any equipment and device, consideration should be given to replace the cables with the equipment.

Another comment from the P&C electrician is that there is only one power supply feeding the protection and control devices for both turbines. It is impossible to carry on the maintenance for one turbine and keep the other turbine running. Consideration should be given to provide separate power sources to each turbine‘s protection and control systems. This will enable one of the turbines to be in service while working on the protection and control devices for the other turbine.

A regular maintenance program for the switchgear and its equipment should be followed. Attention should be paid to inspect the condition of the breaker contacts, check for arcing damage, check the operating mechanism of the breaker and conduct insulation tests for insulation breakdown.

HYDRO should apply infrared thermography to monitor temperatures and thermal patterns while equipment is running in full load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning.

### 5.5.2 13.8 kV/600 V Station Service Transformer

The 750 KVA, 14.4 KV-600V station transformer which is the original installation at 1975, is located inside an enclosed cubicle. Results of tests carried out on the transformer over the years were not available for review during the visit. With the age of the transformer, it is recommended a thorough inspection and a complete over-haul of the transformer and its accessories be performed as soon as possible. With regular maintenance, the transformer should be able to provide satisfactory service for the next 15 years.

The transformer and its accessories, such as the lightning arrestors, the surge capacitors and the cable connections should be part of a regular maintenance program. HYDRO could apply infrared thermography to monitor temperatures and thermal patterns while the transformer is running under load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. The transformer insulation should be tested at regular intervals. Over heating and overloading of the transformer will shorten the life of the transformer.

### 5.5.3 13.8 kV Bus Duct

The 13.8 KV metal enclosed bus duct (Photo: HWD-032) connects the alternator phase bushings to the 13.8 kV alternator circuit breaker located in the 13.8 kV switchgear enclosure. The bus duct further connects the circuit breaker to the unit step-up transformers 13.8 kV bushings located in a low voltage termination box mounted on the transformer. The bus bar material is copper and the bus duct is enclosed.

The bus duct is also constructed of heavy gauge steel plate sections. These sections of duct are bolted together using butt joints (Photo: HWD-033 & 034). During our site inspection HYDRO personnel indicated that this bus duct regularly leaks and some times this water enters the high voltage switchgear building. This may also be one of the sources of leaks for the high voltage switchgear building noted in sub-section 5.7.6. In general the structure of the bus duct was found to be in acceptable condition.

Butt joints are very difficult to make watertight and are likely the source of the leaks noted by site personnel. It appears that attempts have been made in the past to seal these joints with a sealant, which was subsequently painted over. Sealant should not be relied upon as the primary method of sealing joints as it will crack and deteriorate over time. This is especially important at horizontal joints. Cracking of the paint and sealant was noted during the site inspection.

Given that the bus duct is leaking and water from these leaks can find its way onto the existing high voltage switchgear, we recommend that this problem be repaired as soon as possible. This bus duct could be made weather tight by applying hot applied rubberized asphalt roofing compound over the duct similar to how exterior HVAC ductwork is sealed commercially. As well, the bus duct could be covered with cladding used for exterior HVAC ductwork to make it weather tight. Both options are viable. The hot asphalt option is likely cheaper and easier, while the cladding option will allow easier removal and access to the bus duct in the future.

With regular maintenance, the bus duct should be able to provide satisfactory service for the next 15 years. Regular maintenance should include inspection for bus bar rusting and corrosion, insulator tracking and the physical appearance of the enclosure. The bolts at the joints should be re-torqued regularly. Infrared scanning of the bus bar, the joints and the terminations should be performed to identify hot-spots.

### 5.5.4 AC and DC Motor Control Centres

The motor control centres (MCC) provide protection and control for the auxiliary electrical devices for the gas turbine plant. There are two motor control centres - one for the 125V DC equipment and another for the 600V AC equipment. The MCC cabinets house the basic electro-mechanical devices such as circuit breakers, contactors and overload relays. The MCCs were supplied by Cutler Hammer. Eaton/Cutler Hammer or other electrical equipment

distributors can supply compatible replacement parts or replacement kits for any MCC up-grades. The operating handles of the MCC are capable of padlocking. This feature should satisfy HYDRO's locking and tagging requirement.

Unless the operating philosophy of the motor control changes drastically, such as operating the motors with variable frequency drives (VFD), adding feedback monitoring and network interfaces that would require changes to the structure of the MCC wrappers (any changes to the MCC structure will require CSA re-certification), the existing MCC should not require to be replaced and should be capable of operation for a further 15 years.

In addition to regular inspection on the de-energized equipment, infrared thermography inspection should be performed on a regular basis with the equipment energized. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning.

### 5.5.5 DC System – Station Battery and Charger

The station DC system has to provide sufficient capacity to supply the various DC motors and DC powered protection and control systems.

Depending on the battery type, the station battery is subject to various forms of deterioration including: corrosion of posts, cables, hold-downs, and battery trays; cell damage due to severe discharge or overcharge conditions; high resistance connections; and reduced cell capacity. Routine maintenance will serve to detect and remedy these conditions, such that replacement is only required when the general condition deteriorates beyond the point that maintenance is ineffective or overall battery capacity no longer meets the plant requirements. Manufacturers typically specify a design life of 15 to 20 years for wet-cell type batteries, and recommend that the banks be replaced after this period of time.

Common charger and inverter failures include open or shorted rectifier diodes or deteriorated electrolytic capacitors. Replacement is a consideration if vendor support is no longer available, improved output characteristics are desired (i.e. reduced ripple, improved regulation) or the charger or inverter load changes considerably due to changes in the station.

The battery bank is located in a separate cubicle from the breaker cabinet. The 125V 1035 amp-hour VRLA bank for the Hardwoods Gas Turbine was installed in 2005. No leaks or cracks are visible and they are in good conditions. With regular maintenance, the batteries should be able to last for more than 15 years. The 125V charger is the original installation supplied by Gentac. While it is working satisfactory now, it should be replaced in the near future because of the vintage of the charger.

The current inverter was supplied by Pylon. It replaced the original unit on March, 2006 when the original unit failed. Under normal operating conditions, the inverter should be able to provide satisfactory service for the next 15 years.

### 5.5.6 Protection Relays and Synchronizer

The protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Their functions must be sufficient to protect the generating unit against all harmful conditions that may develop and act quickly and appropriately to isolate the abnormal conditions from the system and the alternator. The synchronizing function is critical and requires accurate and reliable monitoring of voltage level, frequency and phase angle. It ensures bump less transition of the alternator to the on-line state, thereby minimizing machine stress and power system transients.

The measuring relays for the alternator protection system are electromechanical relays. For electromechanical relays, ageing of the moving surfaces (such as bearings and bushings for induction discs) due to corrosion or excessive wear can lead to failure of the relay. For measuring relays, ageing of components such as capacitors, resistors, coils and worn contacts are sources of failure. Ageing mechanisms include: corrosion and overheating of contacts; vibration on bearings; wear of bearing surfaces that have exceeded the number of design operations; and failure of insulation material in capacitors and other components due to ageing of the materials.

While a detailed alternator protection review and analysis is not within the scope of this study, a review comparing the existing protection functions with IEEE Std. C37.102-1995 IEEE Guide for AC Generator Protection is provided as follows:.

<u>IEEE recommendations:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 87GN, 51/59GN)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59, 27)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)
- Alternator turn to turn fault (61)
- Voltage balance (60)

<u>Existing Protection Functions:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 64G)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)

- Over and under-voltage (59G, 27G)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)

The existing protection provides adequate basic protection functions to protect the alternator. Compared with the IEEE Standard, the functions that are missing are the generator turn to turn protection (61) and the voltage balance relay (60). An alternator turn to turn fault is difficult to detect. Alternator differential relay will provide protection for alternator internal faults. Depending on the setting sensitivity of the alternator differential relay, it will provide some degree of turn to turn fault protection. The function of the 60 relay is to block the mis-operation of the relays using voltage as a restrain source. There will be costs to incorporate these two functions into the existing protection system. HYDRO's protection design engineer may want to review the scheme and decide whether the level of reduced risk will warrant the level of expenditure required.

Although the existing relays could provide adequate protection, the availability of any direct replacement of the electromechanical relays will be limited. Unless HYDRO has spare relays stocked in their system, it will be difficult or even impossible to obtain direct replacement relays from the manufacturers. The option of replacing the entire protection panel with digital protection relays should be considered because of the ageing considerations of the electromechanical relays, the unavailability of the replacement relays and the increased protection obtained through the multiplicity of advanced functions available in today's digital relays at relatively low cost.

The automatic synchronizing function is provided by the Bailey DCS system. The sync-check relay, PRS-250 is provided by Basler Electric. The design of the sync-check relay has not been changed for the last 15-20 years and is expected to remain that way unless a parts availability issue forces Basler to make a component change.

Historically, the failure rate of electromechanical relays is low (with good maintenance, some of the relays are still in service after 40 years or more) but some of the relay components will age and will fail eventually. The replacement parts and the skilled technicians that are knowledgeable enough to fix these relays are getting harder and harder to find. We suggest that a protection replacement budget and protection modification program should be prepared for the Facility. Replace the relays for the Facility when the opportunity arrives and possibly keep the replaced relays as spare for the other Facility for direct replacement.

With today's technology, one multifunctional digital protection relay could replace several electro-mechanical relays to provide the same protection functions. The GE Multilin Generator Protection Relay replaces the following existing protection functions – 40, 64,87G, 46,59,27,81, 49 and 51V (refer to relay function numbers above). A cost estimate has been provided for one multi-functional digital generator protection relay. If HYDRO's protection philosophy requires

additional relays for backup or for another redundant scheme, the cost estimate will increase accordingly. In the meantime, considering the age of the relays and the non fail-safe design of the electromechanical relays, it may be prudent to test the existing relays in a 2 or 3-year cycle rather than the 6-year cycle as recommended in the HYDRO maintenance program.

### 5.5.7 15 kV Power Cable

The power cables associated with the 750 kVA station service transformer are cross-linked polyethylene (XLPE) insulated cables.

Medium voltage XLPE insulated cables were first installed in the late 1960's. The cable manufacturers and utilities expected the cables to perform reliably for 20-30 years. History has shown that the service life of some of these early cables was far shorter than expected. Many cables failed after only 10-15 years in service. It was later discovered that voids and contamination in the semi-conducting shields, as well as other design and manufacturing deficiencies, led to voltage stress concentrations within the cables. The elevated voltage stress, combined with moisture ingress into the cable structure created what are known today as water trees. These microscopic cavities degraded the insulation over time, ultimately causing the cable to fail. To reduce water tree growth, a special engineered insulating material designed to limit water tree growth called XLP-TR was commercialized in the early 1980's and has been performing reliably in service for over 20 years. Furthermore, the design, manufacturing practice and quality control of power cables have improved drastically within the last 20 years. The design life for the XLPE insulated cable is 20-25 years. The design life for XLP-TR (trees retarded) insulated cables is 30 years or more.

It is our understanding that the 15 kV power cables in the Plant were the original installations that dated back to 1975. The failure rate for power cables installed before early 1980s is high. Our recommendation is to replace the 15 kV power cables installed during 1975 with XLP-TR type insulated cables during the next major Plant shut down. For a 13.8 KV system, the power cables should be shielded and terminated with stress cones.

### 5.5.8 Motors

Properly selected and installed motors are capable of operating for many years with a reasonably small amount of maintenance. Routine maintenance should include inspection for dirt, corrosion, heat, noise, vibration and brush conditions; lubrication of bearings; measuring and trending of the winding insulation.

Motors located inside the buildings seem to be in good physical conditions. All motors should be cleaned, check for signs of corrosion, perform internal inspection, and open the conduit box to check for deteriorating insulation or corroded terminals. Insulation resistance (Megger) test and Polarization Index test should be incorporated into the maintenance program. Any damage

parts discovered during inspection should be repaired and rebuilt. Well maintained motors should provide satisfactory service for the next 15 years.

### 5.5.9 Emergency Backup Diesel Generator

An emergency backup diesel generating unit was installed in 2005. The diesel generator is a self contained package consisting of control panel, battery charger, etc. The 40 kW 600 AC volt diesel generator starts automatically on loss of the AC station service supply to the Gas Turbine and supplies power to a backup battery charger which in turn ensures the integrity of the 125 Vdc supply to the Gas Turbine for protection and control purposes. The diesel generator also provides a backup AC supply for one of the air compressors. The diesel generator is in excellent condition.

## 5.6 CONTROL AND INSTRUMENTATION SYSTEMS

### 5.6.1 Control Module

The gas turbine control module features an ELSAG Bailey INFI 90 DCS installed in 1997 to replace a mainly electromechanical relay control system. The DCS system incorporates three subsystem hot-swappable controllers with redundant backup controllers. The DCS internal network utilizes a redundant communication module. The operator interface uses an industrial PC running PCV and QNX software. The PC is connected to a CRT monitor which displays system graphics and to a keyboard for operator input. A communication link connects the PC to a SCADA system which allows remote control and monitoring of the gas turbine from the Energy Control Center in St. John's, Newfoundland.

There have been some failures recently of input channels at Stephenville. There is very little in the way of replacement cards for the Bailey system other than some sequence of events cards. ABB still sells all of the Infi 90 cards and will support them for an additional 10 years once the product has been discontinued in a few more years. In addition, newer technology is available that will directly replace the older technology and use the same footprint. Stantec recommends stocking spares for all card types.

The interface computer, an industrial PC has been functioning well with only one lock-up recorded in the station log. The interface computer is an older vintage and as such has very little memory capacity and will not run today's software. There is significant risk in not replacing the existing PC since it is older technology and does not have a ready availability of parts. ABB has issued a quotation to HYDRO P&C (copied to Stantec) for a new PC with the latest PCV and QNX software. The new PC will also give HYDRO the ability to do more extensive trending. Stantec strongly recommends the PC and software upgrade be implemented.

The power supply system for the DCS is obsolete. Stantec recommends replacing the power supply system in order to extend the life of the control system out 15 years. ABB has provided a quotation to HYDRO P&C (copied to Neill and Gunter) for a new power supply.

Conditions in the control room were quite humid at the time of the site visit. In addition to the humidity, there are also several sources of heat in the room. Heat and humidity are known to speed the deterioration of electronic components. Stantec recommends that the air conditioning unit for the control module be checked to ensure it is operating properly.

### 5.6.2 Interposing Relays

In August 2006 P&C staff discovered a problem with the control system design at the Stephenville site which also exists at the Hardwoods site. There are at least 8 relays with contacts which are not rated for the DC current which is being interrupted. The problem was detected when welded contacts were found on the relay which controls the fuel recirculation valve at the Stephenville site. Pitting and carbon deposits may be forming on some or all of these relay contacts resulting in increased switch bounce and high impedance contacts. High impedance contacts would cause a reduction of power to the device being controlled. Partial welding would result in late break operation. The overall result of using the incorrect relays could be inconsistent control, possibly with shutdowns or non-starts. P&C staff has begun to install interposing relays at Hardwoods. The final connections will be made when the units can be shut down long enough to do the work.

### 5.6.3 Vibration Monitoring

The existing vibration monitor by IRD was installed in 1975. The monitor appeared to be functioning well at the time of start up during the site visit.

There have been instances in the past when GGA would not start due to vibration problems. In April 2000, GGA was sent to Scotland for this problem to be repaired. The station log does not indicate any vibration problems since then. Vibrations seem to be worse on cold days, when the machine is cold and has not been cycled for a while. Stantec would recommend more frequent cycling in the winter months.

Operations staff and P&C are of the opinion that the vibration monitoring equipment needs to be replaced. In November 2005, some of the vibration cards burnt out. The equipment is obsolete and there will likely be more failures in the next 15 years. According to P&C staff, HYDRO has an approved capital budget item to replace the existing vibration monitors at both sites in 2008. The existing transducers are functioning well but are obsolete. They are still available on the market, but Stantec recommends replacing these with newer accelerometers. It would be also be advisable to purchase spares.

### 5.6.4 Temperature Monitoring

Temperature monitoring is an integral part of the DCS system whereby critical temperatures are brought into the DCS either as analog inputs from RTD's and thermocouples or as discrete signals from temperature switches. Bearings, windings, glycol, oil, fuel, and air are some of the quantities being measured. Critical temperatures can cause alarming, power limiting or unit shutdown as appropriate.

The thermocouples should use terminal blocks designed for thermocouples. P&C has indicated that proper terminal blocks are not being used in all cases. Stantec was not able to open the terminal boxes to examine. NLH should replace the terminal blocks on an upcoming planned maintenance.

Temperature element failures are likely to occur over the next 15 years. One approach which HYDRO could take with regards to thermocouple and RTD maintenance is to replace the elements on each sub-system at the time of a major overhaul. Elements which can be easily changed and have no shutdown initiation can be replaced as they fail. Dual element thermocouples are likely not a cause for concern since the second element is available when the first one fails. Existing spares should be reviewed.

Temperature switches have not shown any failures at Hardwoods. Exact replacements will not likely be available over the next 15 years, but it is very easy to source an equivalent switch with a compatible temperature range. Temperature switches are dry contact devices so there is no issue with supply voltage level. Installation detail will not likely be an issue as the switches are normally surface-mounted or mounted with a standard pipe size and thread type. Switch size should not be a problem since instrumentation generally shrinks in size over the years and will therefore fit in the footprint of the device being replaced.

### 5.6.5 Instrument Calibration

Stantec could not find any evidence that transmitters and switches are being periodically calibrated. Operations could not recall these activities being done. Stantec recommends routine calibrations of all instruments. Initially all instruments should be calibrated and the frequency of recheck should be dependent on the stability of the instrument. Non stable instruments should be replaced.

### 5.6.6 Control Valves

There are several control valves including a temperature regulating valve in the glycol system, a pressure controlled valve in the lube oil system, and control valves in the fuel system. These valves are original equipment with the exception of the motorized valve at the fuel tank. As such, it may be difficult to get spare parts and support, although the station logs have indicated replacing internals in some of these valves. NLH should examine the design conditions for

these valves to determine if the conditions can be met today in a package that is a direct replacement. If not, some redesign of piping will be required should a valve have to be replaced. This is best determined in advance so a plan can be generated and sufficient spares stocked. Stantec recommends one spare for each of the original equipment control valves.

Anti-Icing Valve

There have been several incidents of shutdown due to anti-ice valve failure. Stantec recommends at least making the response to an anti-ice valve operation a power limited condition rather than a full shutdown. The logic can likely accommodate this change.

Fuel Tank Motorized Valve

The motorized valve on the fuel tank is new and works well with one exception. There appears to be a deficiency in the logic in which the valve will not open until a certain time delay after an engine has successfully completed its start up sequence. Once the engine has started it is consuming fuel oil while the motorized valve is still closed. Eventually it uses all of the fuel in the line between the engine and the fuel tank, and the unit shuts down. Logic changes appear to be in order to correct this problem.

### 5.6.7 Clutch Proximity Switch

A proximity switch in the clutch detects the engagement of the clutch between the turbine and the alternator. There have been failures of the proximity switch in the past and there was another failure during this site condition study. There appears to be a physical interference issue between the clutch mechanism and the proximity switch when the clutch engages. Refer to sub-section 5.2.6 for further details. As a side issue, it was noted that the gas turbine unit is coming to a complete shutdown after a time delay when engagement is not detected. Stantec recommends that the logic be investigated to see if a complete shutdown can be avoided. It may be feasible to leave the machine in sync-condense mode.

### 5.6.8 Fuel Temperature

There have been failed light-offs due to cold fuel. Stantec supports Hydro's recommendation to put the cold fuel through a recirculation period to heat the fuel prior to light off during cold winter days. This recirculation operation could be left as a manual operation or programmed into the logic to occur based on a given ambient temperature and cold machine starts.

The fuel valve start position has been adjusted at times due to ambient temperature to achieve light off. Perhaps this adjustment can be eliminated with the recirculation modification discussed above.

There is an additional issue with fuel temperature control. The temperature sensing element for the fuel shutdown circuit is located directly in the fuel heater, whereas the sensing element for fuel temperature control is located in a pipe several feet away. Stantec recommends that the two temperature sensing elements be located adjacent to one another to allow the control system to do its job before the shutdown system kicks in.

### 5.6.9 Fuel Storage Tank Level Switch

The Hardwoods site does not have a low level cutout switch on the storage tank, whereas the Stephenville site does have cutout switches on its storage tanks. Stantec recommends the installation of a low level cut out switch to prevent running the pumps dry or pumping out tank bottoms in the event of the level transmitter failing. NLH should examine its current logic to determine if the existing risk of using a transmitter only is acceptable.

### 5.6.10 Fuel Storage Tank Wiring Conduits

There are a few holes in the liquid tight conduit around the Motor Operated valve and junction box. There is also a separated PVC conduit joint in the conduit between the storage tank and the fuel unloading building. These should be fixed to prevent further water ingress.

### 5.6.11 Remote Control and Monitoring

Remote control and monitoring of the Hardwoods Gas Turbine at the Energy Control Centre (ECC) in St. John's is accomplished through a SCADA system interface to the DCS. The SCADA system is not part of the Condition Assessment Study scope.

P&C personnel have indicated that future upgrades are being considered. In particular, data transferred from the Gas Turbine sites to ECC could be expanded and stored on a PI historian at ECC. According to P&C personnel, HYDRO has a central group that deals with SCADA maintenance and upgrades.

### 5.6.12 Junction Boxes

One of the junction boxes has some corroded terminals on the outside of GGA. With the alternator operating as a synchronous condenser at the time, Stantec did not get an opportunity to look inside this box, but it was pointed out by the turbine operator. Of course, all corroded terminals should be replaced. The junction box covers are in general quite water tight due to the large number of bolts holding the covers on. NLH has begun putting an extra stainless steel cover over some boxes where there have been water problems. These are working well.

The main junction box on the outside of the control module building is in a state of disarray. Wire ducts are overfilled (Photos: HWD-035 & 036). Cables are hanging this way and that. Normal housekeeping practices were not followed during the rewiring of these cables for the

DCS installation. Stantec suggests that the congestion and housekeeping issues be corrected to enable trouble shooting. Since there have been a few examples of failed cables, NLH may want to consider replacing all cabling from this box to the field.

Another issue in this junction box is the presence of the 600V cabling. The terminals have been guarded with Plexiglas to prevent accidental contact by service personnel. NLH should find a new location for the 600V terminals should it decided to mount a re-cabling effort.

Both turbine units still have the original on-engine electrical junction boxes. It is recommended that these boxes be moved off-engine, to isolate the terminations from engine vibration and heat.

### 5.6.13 General Comments

There is no guarantee that any particular instrumentation component will last another 15 years without repair or replacement. However, most of the instrumentation will have suitable replacements.

It would be a beneficial project for HYDRO to create a specification sheet for each piece of instrumentation. Nameplate data, set points, ranges of operation, flange rating, face to face dimensions, etc, could be recorded. Where nameplates and other information is unreadable or unavailable, the exercise of creating the spec sheets will require a bit of research but could be done under non-breakdown conditions.

Having this information available electronically will make sourcing of suitable replacement instruments easier. Identifying replacements could be done in advance to build a spares inventory. The spec sheets could identify several instruments which could use a common spare. Maintenance notes could be added to the spec sheets to track repairs and calibration.

Some of the more complicated retrofits, such as a control valve which requires piping modifications, could be done on a project basis when the valve nears the end of its serviceability.

Stantec is not aware of the program used by HYDRO for the routine calibrations or testing of switches. HYDRO should confirm that the current set points of all instrumentation are in line with manufacturer's original operational design set points. Further, HYDRO should confirm that all instrumentation is functioning properly.

Spares should be stocked for each type of instrumentation device when delivery lead times are long.

## 5.7 BUILDINGS

### 5.7.1 Control Building

The existing gas turbine control building is a single story prefabricated and packaged steel structure supported by cast-in-place concrete foundations. The exterior building envelop consists of heavy gauge steel plate and roofing. The exterior coating on the building was found to be in poor condition. Surface corrosion and coating failures were noted in several locations on the walls and roof of the building. Based on the level of corrosion we recommend that the exterior of this building be cleaned, prepared and recoated within the next two (2) to five (5) years (Photo: HWD-037).

The structural steel framing for this building was not visible from the interior of the building. Therefore, no structural inspection was carried on the interior of this building. The concrete foundation was visually inspected and no significant cracking or deterioration was noted.

Water stains on the ceiling tiles inside the building were noted in two locations, indicating roof leaks in the past. A visual inspection of the roof revealed that there are lap joints in the roof panels approximately every four feet. As well, it appears that the joints in the roof panels have been coated in the past in an attempt to seal them. Lap joints are very hard to make watertight. This roof is also flat making it even harder to make a watertight joint at these locations. Given the past leaks, difficulty making watertight joints with this type of roof and the equipment housed inside the building, we recommend that a new sloped metal roof be installed over the existing roof (Photo: HWD-038).

### 5.7.2 Fuel Unloading Building

The existing fuel unloading building (Photo: HWD-039) is a single-story prefabricated structure located adjacent to the fuel oil containment dyke. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. The building is ventilated by a single exhaust fan and a supply louvre.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment we also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition with minor shrinkage cracking in the floor slab. There were no concrete containment curbs in this building. Therefore, should a pipe or pump leak inside the building, there is no way to contain the spill and this will likely result in a fuel oil spill.

The exterior cladding on the building was found to be in generally good condition with only some minor corrosion noted along the bottom of the wall panels. The roof however was found to have a significant amount of corrosion and will likely require replacement within the next two (2) years (Photo: HWD-040).

The existing concrete dyke at the off-loading station is in good condition with no visible cracking. However, the timber posts and guard rail protecting the concrete dyke and piping was in very poor condition and in need of replacement (Photo: HWD-042). It was noted that the area surrounding the concrete off-loading dyke was just gravel (Photo: HWD-041). We recommend that this area be paved to help contain and facilitate clean-up of any minor spills that may occur when the off-loading hose of the delivery truck is being hooked or unhooked to the oil transfer system.

### 5.7.3 Fuel Forwarding Building

The existing fuel forwarding building (Photo: HWD-043) is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. The building is ventilated by a single exhaust fan and supply louvre.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment we also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition. While there are no concrete containment curbs in this building, there is a floor trench inside the building running parallel to the perimeter walls that collects all spills and transfers the fluid via an underground drain piping system to a sump pit that is fitted with a level alarm. The underground piping system from the floor drains to the sump was replaced 2 years ago.

The exterior cladding on the building was found to be in generally good condition with only some minor corrosion noted along the bottom of the wall panels on the highway side of the building. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the next 2 years (Photo: HWD-044).

The timber posts and guard rail protecting this building were found to be in very poor condition and in need of replacement (Photo: HWD-045).

### 5.7.4 Auxiliary Module Building

The existing auxiliary building is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. It appears that the original building was expanded in the past to include the current compressor room.

The exterior cladding on the building was found to be in generally good condition. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the 2 years (Photo: HWD-046).

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition. We also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition.

### 5.7.5 Maintenance and Parts Storage Building

The existing maintenance and parts storage building (Photo: HWD-047) is a single-story prefabricated structure. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade.

The exterior cladding on the building was found to be in generally good condition. It appears that the siding and windows on the front of the building have been repainted in the last couple of years. The window located at the rear of the building requires painting and corrosion was noted at the bottom of the wall panels. Surface corrosion was noted on the roof in several locations. We recommend that the roof be cleaned, corrosion removed and repainted within the next two (2) years.

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion damage or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition. We also reviewed the condition of the existing concrete slab on grade. The slab on grade was found to be in generally good condition.

### 5.7.6 High Voltage Switchgear Building

The existing high voltage switchgear building (Photo: HWD-032) is a prefabricated and packaged building. This building is constructed of structural steel with heavy gauge steel plate cladding and roofing. The building is supported by cast in place concrete foundations. No

significant cracking or deterioration was noted in the foundation during the visual inspection. The majority of the interior of this building is filled with high voltage switchgear and a large portion of the structure could not be inspected.

During the site inspection surface corrosion and coating failure was noted in several locations on the exterior as well as the interior of the building. Based on the level of corrosion we recommend that this building be recoated within the next five (5) years.

During the site inspection HYDRO site personnel informed Neill and Gunter that they have had leaks in this building in the past. They also indicated that they have had trouble determining the source of the leak and repairing it. The roof is constructed of heavy gauge steel plate which is simply lapped at the joints. It is very difficult to make a watertight seal with this type of joint. We therefore recommend that a new roofing system, such as a modified bitumen roofing membrane, be applied with hot asphalt directly over the existing roof. This new roof membrane will be a large improvement over the existing roofing.

### 5.7.7 Emergency Back-up Diesel Generator Building

The existing diesel generator building is a single-story structure that is approximate 150 square feet in size. The exterior of the building consists of vertical sheet metal siding and asphalt shingle roofing. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. For oil containment, the building has a floor trench that is piped underground to the same sump noted in sub-section 5.7.3 for the Fuel Forwarding Building. The interior of the building is finished with painted plywood.

The exterior cladding, roofing and doors on the building were found to be in good condition and no deterioration or corrosion was noted. The concrete slab on grade and interior plywood finishes were also found to be in good condition. An exhaust fan and louvre have also been installed to provide ventilation for the building.

It was noted that in one corner of the building the bottom one to two inches of the sheet metal siding was buried under the crushed stone gravel surrounding the building. We recommend that this be remedied so that the sheet metal siding is no longer buried. This will help prevent water migration into the building and premature corrosion of the cladding.

### 5.7.8 General Comments

Only visual inspections were carried out as part of this assessment. Not all structural components were visible or accessible at the time of inspection. No non-destructive or destructive testing was carried out on any of the structures noted above as part of the inspection. Therefore, this assessment should not be considered an exhaustive inspection of all civil/structural components. As well, it is important to note that no detailed analysis was completed as part of this assessment to determine the adequacy of different structures for their purpose.

## 5.8 ENVIRONMENTAL

The Condition Assessment Study addressed several environmental issues as they relate to the Hardwoods site, specifically soils contamination and air emissions.

**Soil Contamination**

A review of several environmental reports provided by HYDRO indicates there have been a number of documented spills and leaks of petroleum products at the Hardwoods site over the past 30 years. The petroleum products include #2 diesel fuel, lubricating oils, transformer and capacitor oils. These spills and leaks resulted in soil contamination at various locations including the diesel fuel bulk storage tank area and the gas turbine / terminal station area. The following are a few examples of recorded spills and leaks:

- In 1978 a spill of approximately 78,000 Litres of diesel fuel resulted from a sump pit near the gas turbine overflowing when a valve was left open. The contaminated soils were cleaned to the satisfaction of the Department of the Environment.
- In 1991 a spill of approximately 1,600 Litres of bearing oil resulted from a sump pit near the gas turbine overflowing.
- In 1991 a spill of approximately 1,200 Litres of lubrication oil resulted from a pipeline failure and subsequent sump pit overflow.
- In 1994 a spill of approximately 7,000 Litres of diesel fuel resulted from a rupture in the pipeline leading from one of the two bulk storage tanks. At the time, the dyke surrounding the tank was found inadequate to contain the spilled fuel. The contaminated soils were cleaned to the satisfaction of the Department of the Environment. In 1997, the storage tank was removed from the site, the dyke containment ability was increased and a new HDPE liner was installed beneath the remaining tank and around the dyke walls. The remaining storage tank was inspected and found to be in good condition. Refer to section 5.4 for further details on the fuel storage tank area and the remedial work carried out.
- There are also recorded instances of a transformer leak (1.2 Litres) and a PCB oil leak (2 Litres) when PCB's were used in capacitor banks. In recent years, the PCB capacitors have been phased out and replaced with components that meet regulatory requirements.

While these spills and leaks were cleaned to the satisfaction of the Department of Environment, impacts to the soils are still being encountered at various locations throughout the site. Since 1999, HYDRO has initiated a number of environmental studies to investigate these impacts. These studies include:

- AGRA Phase I Environmental Site Assessment in 2000
- AGRA Limited Phase II Environmental Site Assessment in 2001
- Jacques Whitford Tier II Risk Assessment in 2002.

The Jacques Whitford Study concluded that petroleum hydrocarbons are present in the surface soil and groundwater at the site but do not appear to be migrating off the site. In 2003, the

Newfoundland and Labrador Department of Environment in response to the Jacques Whitford Report issued a Letter of Closure stating that “the Department is satisfied, at this point in time, that the stated level of contamination remaining on the property, in the area addressed by the Report, does not pose an unacceptable risk to human health and the environment”. The Department issued two stipulations (i) workers engaged in future sub-surface excavations on site must be made aware of the potential risks of exposure to the remaining contamination and (ii) the on-site water supply shall not be used as a drinking water source.

The Study did not take an exhaustive look at environmental issues at the Hardwoods site. The issue of soil contamination is noted in this Report for the express purpose of making the reader aware that such conditions exist at the Hardwoods site and any significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work, could involve costs for soil remediation.

Air Emissions

The gas turbines produce air emissions related to the combustion of diesel oil. The exhaust emissions are not filtered or treated. There is no Continuous Emissions Monitor System (CEMS) on either exhaust stack. The various HYDRO inspection check lists included in Appendix 5, do not list exhaust stack emission manual sampling as an activity. Data on stack(s) emissions testing that may have been conducted by HYDRO in the past was not available for review.

Exhaust emissions from the gas turbine fall under Newfoundland and Labrador Regulation 39/04, Air Pollution and Control Regulations (O.C. 2004-232). The Regulations list limits on the concentration of air contaminants due to all emitting sources. The concentrations are defined by periods of time during which the concentrations exist. It would appear that the present operational mode of the gas turbine, as predominately synchronous condenser operation, would be within the criteria listed in the Regulations. If the predominant operational mode in the future is generation on a somewhat continuous basis, HYDRO should be aware of the potential application of the air contaminant limits in the Regulations.

The Regulations state that an owner or operator who installs a new or modified emission source shall employ the best available control technology with respect to air emissions. This requirement however does not apply to parts replacement but would likely apply to the installation of a new gas turbine.

The Study did not take an exhaustive look at air emission issues at the Hardwoods site. The issue of air emissions is noted in this Report for the express purpose of making the reader aware that any future generation operational mode changes or significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work could involve the application of the criteria in the Regulations.

# 6.0 STEPHENVILLE GAS TURBINE FACILITY CONDITION ASSESSMENT

## 6.1 GENERAL

This Section documents Stantec's observations and comments on the condition of equipment and structures at the Stephenville Gas Turbine Facility. These comments are based on observations during the site visit on July 17/18, 2007, discussions with HYDRO staff and a review of documentation provided by HYDRO. Photographs taken during the site visit are included in Appendix 13. The Facility was broken down into the following areas for the condition assessment study:

- Gas Generators/Power Turbines and Auxiliary Systems
- Alternator/Excitation System
- Fuel Oil System
- Electrical Systems
- Control & Instrumentation Systems
- Buildings

The Section contains a number of recommendations on refurbishment work that HYDRO should consider in order to provide for the reliable operation of the Facility (Photo: SVL-001) for a further 15 years. **The recommendations and associated costs are summarized in Appendix 6.**

## 6.2 GAS GENERATORS/POWER TURBINES AND AUXILIARY SYSTEMS

### 6.2.1 Rolls Royce Olympus C Gas Generator Engines A & B

The Gas Turbine consists of two Rolls Royce Olympus C, 25 MW Gas Generator Engines (A and B) fired on #2 Diesel Oil, each driving a Curtiss Wright Power Turbine equipped with a SSS clutch. Each Gas Generator Engine has an air intake structure and each power turbine has an exhaust stack. New Olympus C Gas Generator Engines are no longer available from Rolls Royce. At the present time there are approximately 14 Olympus C Gas Generator Engine assemblies available in the market. In addition to the refurbishment of the existing Gas Generator Engines as recommended herein and in line with HYDRO's plans to keep the Gas Turbines at both sites operational for a further 15 years, it may be advantageous for HYDRO to consider obtaining a whole spare engine assembly as eventually all the spare Olympus C units will be scrapped.

The Olympus "C" type 2022 gas generator is a straight flow tubo-jet employing axial flow compressors driven by an axial flow turbine. A diagram (Figure 2-3) illustrating a cross-sectional view of the Olympus C Gas Generator is included in Appendix 4 to illustrate the various components comprising the Gas Generator. The combustion system uses eight combustors

each with a burner contained in an annular outer casing. The eight combustion chambers are arranged equidistant around the turbine numbered from the top clockwise when viewed from the rear. An external air compressor system provides air to the starter motors. A Woodward Electronic Governor controls fuel flow. Further details on the Gas Generator auxiliary equipment can be found in sub-section 5.2.2.

Provision is made for heating the compressor entry guide vanes, nose fairing and the leading edges of the air intake casing during adverse weather conditions. The heating medium is air tapped from the #6 vane of the compressor casing and conveyed through a pipe to an electrically operated anti-icing hot air valve.

The lubricating oil system comprises an external tank that contains a heater system and a cooler that is cooled by means of the incoming fuel to the turbine combustors. The remainder of the system comprises pumps, level control system and oil delivery temperature control system. The return oil is pumped through a micro filter back to the reservoir tank.

A vibration pick-up is mounted on the gas generator casing flange, and it has a frequency range of 20-400cps. The signal is modified to read amplitude peak to peak and the system includes for alarm and trip points at preset levels.

Rolls Royce Olympus C Gas Generator Engine A (S/N 202204) externally appears to be in fair condition, above average for the total time in service since installation in 1975. Significant corrosion and depletion of the blade exterior coatings was noted. A fibreoptic borescope inspection of one (1) combustor assembly in the 7:00 position, revealed no major unserviceable conditions to all visible engine internal components. Unit hot gas path general condition is commensurate with total time since new. Inlet air system deficiencies, allowing particulate such as rust to form and be ingested by the engine, have resulted in significant abrasive damage to the Compressor first stage blading, inlet bulletnose assembly and Compressor front frame inlet guide vanes.

The Gas Generator Engine A auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Gas Generator Engine A has never been overhauled, and appears to be in fair condition. Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that this engine assembly be removed, disassembled to allow for detailed internal inspection and major refurbishment as required.

Rolls Royce Olympus C Gas Generator Engine B (S/N 202224) externally also appears to be in very good condition, above average for the time in service since last overhaul. No exterior corrosion was noted, nor depletion of the blade exterior coatings. A fibreoptic borescope

inspection of one (1) combustor assembly in the 7:00 position, revealed no unserviceable conditions to all visible engine internal components. Inlet air system deficiencies allowing particulate such as rust to form and be ingested by the engine have resulted in minor abrasive damage to the compressor first stage blading.

The Gas Generator Engine B auxiliary systems appear to be in serviceable condition - oil supply, scavenge, starting, ignition, cooling air, fuel delivery and vibration monitoring systems. The on-engine controls appear to be in serviceable condition - speed indication, temperature sensors and Woodward speed governor.

Gas Generator Engine B was last overhauled in year 2000, and appears to be in good condition. Should HYDRO choose to have the complete package refurbished and operate for an additional 15 years, it is recommended that this engine assembly be removed and disassembled to allow for detailed internal inspection and refurbishment as required.

It is suggested that compressor washing be conducted every 6 months. Crank soak washing is recommended over fired wash. A recommended cleansing agent – B&B 3100 – should be diluted with distilled or de-ionized water. Distilled or de-ionized water should also be used for the follow-on rinse.

HYDRO provided a copy of Inspection Report prepared by ALBA POWER reflecting their more extensive borescope inspection work carried out on the Hardwoods Olympus C Engines in May 2007. We have included the ALBA Report in Appendix 4 as the ALBA observations and recommendations are similar to the conclusions arrived at in this Study. In addition, the ALBA photos clearly highlight the issues associated with each Engine.

### 6.2.2 Gas Generator/Power Turbines Auxiliary

Some auxiliary system components are obsolete and are no longer supported by the manufacturer or have been supplanted by more modern equipment. These include;

- Ignition exciters
- Vibration monitoring system.
- Speed governors/fuel valve assemblies.

Replacement auxiliary assemblies of current design are readily available however they do entail costs that will need to be considered. HYDRO should decide on its requirement for plant availability so that alternative strategies of installing new systems versus holding a stock of spare parts on site can be compared.

Woodward Governors

The Woodward speed governors are covered in sub-section 6.2.1 wherein it was stated that the on-engine auxiliaries were observed to be in satisfactory condition. Spares for the governors are readily available.

Gas Generator Bearings

The major line bearings were not accessible in the time allotted for inspection. The gas generator engine line bearings (8) are of the rolling element type. Inspection of the magnetic chip detectors indicated satisfactory bearings condition.

Gas Generator Lube Oil System

The engine's lube oil supply/scavenge system is self contained and driven by the engine assembly. It appears to be in satisfactory condition. The oil is cooled by means of a heat exchanger that uses incoming fuel oil as a coolant for the engine lube oil.

Compressed Air System

There are two starting air compressors mounted on the auxiliary module in an enclosed room within the Control Building and two storage tanks for start-air located outside the Control Building. The system provides sufficient air for three engine starts. The two air-cooled compressors are rated to deliver air at a discharge pressure of 500 psig. Each compressor contains an air inlet filter and silencers, and are driven by two 7-1/2 HP AC motors.

The two compressed air storage tanks (receivers) are sized to provide sufficient volume for at least three repeated starts of the gas generators. Relief valves are mounted on each tank to protect it from overpressure. Water traps are provided to automatically remove the condensed water from the bottom of each of the storage tanks. There is also a heating cable included in the drain circuits.

The control system provides conventional start/stop control with lead/lag compressor selection. Compressor instrumentation appears in good working order.

The compressed air system is of standard design and appears to be in reasonable condition for a further 15 years of service however the exact same components may not be available for the coming 15 years. A single spare compressor for both sites is probably adequate to provide for continuous plant availability.

Starter Motors

The starter motors have provided high reliability, but the model is no longer supported by Rolls Royce. It is suggested that a spare unit compatible with all four gas generators, should be carried by HYDRO. (The inventory of spare parts dated 2004, includes one starter motor assembly).

### 6.2.3 Inlet Air Systems A & B

The Stephenville inlet air system to the gas generators are in two plenum modules A and B (Photo: SVL-001). Each contains the gas generator inlet air filters, bypass doors, silencers between the inlet filters and plenum, hoist provisions for gas generator removal and installation. The primary air flow is introduced into the filter enclosure passing through louver vanes for water separation and then through fiberglass filter packs for fine particle separation. The primary airflow path then continues through the inlet silencer and into the inlet plenum. The inlet air filtration system at Stephenville is different to that installed at Hardwoods.

In the event of extreme conditions where a high degree of contamination exists, blow-in doors located in the rear wall of the inlet filter enclosure will open when the pressure drop across the filters and silencers exceeds three inches of water. Whenever the counterweighted blow-in doors open, an indicator light will be illuminated on the control panel in the control module to alert the operator that a filter inspection or media change is required. An access door is provided in the rear wall.

The inlet silencer duct is located between the inlet filter and plenum. Contained in the silencer duct are acoustically treated parallel baffles made of dense fiberglass sandwiched between perforated steel panels. The silencer is designed so that the sound power level in decibels is within specified limits. The system is designed to achieve noise levels at a distance of 1,000 feet less than 54 dBA or 95 dBA at a distance of 3 feet.

Entrance to the inlet plenum is accessible through the hinged bolted doors located at the forward end and through a removable 24” x 12” panel. At the rear of the plenum, a split septum door is located which is cut away to permit the gas generator inlet flare to protrude into the plenum area about 6½ inches.

A secondary air supply is provided through a duct mounted on top of the turbine module. The secondary air entrance is provided with a bird screen and the air passes through a fiberglass assembly consisting of 2’ x 2’ x 12” elements. The air then passes through silencer baffles to two electrically operated fans and is discharged into the front end of the turbine module to limit the temperature of the air to 125$^{o}$F (52$^{o}$C). The fans come on whenever the unit is started and remain on during operation and after shutdown until the temperature sensing probe at the rear of the turbine module senses a temperature below 115$^{o}$F (46$^{o}$C).

The inlet structures are constructed of structural steel plate and framing supported by a cast-in-place concrete foundation. The concrete foundation was found to be in adequate condition and

there were no visible cracks noted. As well, no significant structural steel issues were noted during the inspection. The exterior of the air inlet structures was recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted.

There were several items noted during the inspection that require maintenance work. It was noted that the coating on the concrete slab located inside the inlet plenum was peeling. The paint peeling can then be sucked into the inlet of the gas turbine and potentially cause damage to the turbine. We recommend that the concrete slab be cleaned, prepared and coated with breathable masonry paint such as Loxon by Sherwin Williams (Photo: SVL-003).

Surface corrosion of the steel and flaking of the steel coating was noted inside the air inlet structures. The corrosion has caused the steel coating to flake as well as rust flaking. This loose material can then be sucked up by the gas turbine and potentially could cause damage. We recommend that the interior of the air inlet plenum and silencers be sand blasted and recoated (Photo: SVL-002).

The interior of inlet air plenums A and B show signs of corrosion damage. The basic structural integrity is good, and can be returned to satisfactory condition with basic cleaning and replacement of the surface coatings.

Significant corrosion was also noted in the trough under the access doors for both air inlet structures. This corrosion is likely a result of water accumulation in the trough over extended periods of time. We recommend that the following items be completed to repair this problem and help prevent it from reoccurring:

- Sand blast and coat all areas corroded under the access doors to the air inlet plenums (Photo: SVL-004).
- Weld new plates inside the troughs that will drain water to the centre of the trough.
- Drill a weep hole in the exterior of each air inlet structure to allow water to drain from the trough under the access doors.
- Replace the weather stripping on the access doors.
- Install a new drip cap over both access doors similar to the drip caps over the man doors on the gas generator/turbine modules and alternator modules (Photo: SVL-005).

The inlet bell-mouth assemblies are not fitted correctly to the engine, causing inlet air turbulence and loss of efficiency. In the case of air inlet system A, the rubber sealing strips around the exterior doors are deteriorated to the point of cracking and no longer making effective seals against unwanted air leaks (Photo: SVL-005). In the case of air inlet system B, the inlet bell-mouth assembly is out of alignment approximately .250” creating significant turbulence to the inlet air stream. As the units, during full power settings, ingest over 240 lbs/sec, the importance of correct bell-mouth fitment cannot be overemphasized. Misalignment will create turbulence in

this air stream, accelerating compressor blade root wear, and costing up to 500kW of potential power output loss.

Both inlet air systems show signs of significant deterioration and corrosion damage. This deterioration is compromising the effectiveness of the inlet air filtration and contributing to abrasive wear to the engines' compressor components. HYDRO staff should be aware of the criticality of keeping the inlet air systems clean, and not allow small rocks and debris to enter into the systems during periodic maintenance.

There is evidence of silica sand, rust scale, small rocks in the inlet plenums, which eventually will be ingested by the turbine engine.

It was also noted that the steel grating on the platforms attached to the air inlet plenums was in poor condition having significant corrosion in some areas. We recommend that the grating on both platforms attached to the air inlet structures be replaced (Photo: SVL-006).

Access to the top of the air inlet structure is provided by a ladder. However, it was noted that there was no fall arrest system in place at the top of the air inlet structure. We recommend that new 42" high handrail with kick plates be installed around the perimeter of the top of each air inlet structure for fall protection.

It was noted that holes in the existing structure for attaching hoist beams have enlarged significantly. We recommend that new plates with holes of the proper size and location be welded to the existing structures to prevent pullout of bolts during lifting procedures for safety purposes (Photo: SVL-007).

### 6.2.4 Exhaust Stacks A & B

The exhaust stacks for both power turbines (Photo: SVL-008) are constructed of a heavy gauge steel plate with stiffeners on the exterior of the structure, with heavy gauge steel plate liners on the interior. Based on the drawings viewed on site, the interior liners of the exhaust stacks are welded to the exterior structure with horizontal bent plates around the perimeter of the structure and installed at regular vertical intervals. It is our understanding that the void between the interior liner and exterior structure is filled with insulation. The snow doors on the exhaust stacks were modified from electric actuation to pneumatic operation in 1989.

The exteriors of the exhaust stacks were recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the exhaust stacks was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration. It was noted that the exterior gusset plates on the four corners of the exhaust stack for Power Turbine B were bent. These gussets plates were likely damaged during transportation or erection of the exhaust stacks.

This does not present any structural concerns at this time as the steel structure in the vicinity of these gusset plates is in good condition and does not show any signs of deformation.

The existing handrails on the platforms attached to the exhaust stacks are only 36" in height, do not have kick plates and therefore do not meet fall protection regulations. We recommend that kick plates be added along with additional top rails to the existing handrails to extend the height of the railings to a full 42 inches. It was also noted that the floor grating on these platforms consisted of expanded metal mesh which distorted significantly under foot. We recommend that this be replaced with standard bar grating which is much stronger and durable (Photo: SVL-008).

The existing access hatch for the exhaust stack of Power Turbine B was also reviewed. These access hatches are quite small, making access for HYDRO site personnel difficult. The current hatch arrangement also makes removal and reinstallation difficult and time consuming. To make the hatches water tight caulking must be applied to all joints. Caulking should only be relied upon as a secondary seal and not the primary method of making a joint weather tight. Should the hatch have to be removed during the winter months, it would be very difficult to make the hatch weather tight as the caulking will not setup at low temperatures. We recommend that the existing hatches be replaced with operable man doors with proper flashings and weather stripping (Photos: SVL-009 & 010 & 011).

HYDRO personnel also indicated that they cannot easily access the pneumatic cylinders which operate the snow doors on top of the exhaust stacks. We recommend that the existing platforms be modified to support new ladders that will allow site personnel to visually inspect the condition of the pneumatic cylinders and hoses (Photo: SVL-008).

In both exhaust stacks, cracking is evident at the joint of three (3) flat planes within the vertical stacks in two (2) locations. This cracking was noted in the bottom south-west and north-west corners of the exhaust stack liner for Power Turbine B. These were viewed from the access door of the exhaust stack. Cracking was also noted in the bottom south-east and north-east corners of the exhaust stack liner for Power Turbine A. These cracks were viewed form inside the clutch module for Power Turbine A. It is believed that this cracking exists in all four bottom corners of the liner in each exhaust stack. The cracks do not appear to be compromising the structural integrity of the exhaust stacks as a whole, rather may be a result of thermal cycling over time, relieving stress at these points.

Based on the drawings viewed on site for the exhaust stacks, it appears that the exhaust stack liner is rigidly fastened to the exterior structure. With this arrangement, the interior liner will heat up and expand due to the hot exhaust gases from the gas turbines, while the exterior structure is insulated and will therefore remain relatively stable in temperature. Since the liner is constricted by the outer exhaust stack structure, high stresses likely build up in the liner. The stresses would be highest at the bottom of the liner where it gets the hottest and at locations of

discontinuities, such as joints and corners. Given the location and orientation of the cracks noted above, it is believed that these cracks are a result of the thermal expansion and contraction of the exhaust liner which is constrained by the exterior structure.

In the south-east corner of the exhaust stack for Power Turbine A, it appears that a former crack in the liner was repaired by welding the crack. However, a similar crack in the liner has appeared adjacent to the repaired crack. Simple weld repairs may repair the cracking, however over time, it is highly likely that the cracks will reappear, and if the areas in question are ruggedized (ie. weld repairs with reinforcing materials), it is also likely that the stress cracking may appear in the next weakest location due to the nature of thermal expansion/contraction in flat planes. The remainder of the exhaust systems appears to be in satisfactory condition.

### 6.2.5 Curtiss Wright Power Turbines A & B

There are two Curtiss Wright Power Turbines A and B. Each Curtiss Wright power turbine is a two-stage axial flow unit with the rotor assembly and main shaft supported as a cantilever by two white metal bearings housed in a pedestal. The power turbine unit is connected to the gas generator by a gas duct incorporating a bellows joint. The gas generators receives ambient air from the air inlet plenums and delivers high temperature and pressure gas to the power turbines which converts the thermal energy into rotating mechanical power. The power turbines output shaft is coupled to the alternator through SSS clutches.

The two-stage axial flow rotor consists of two rows of cast Stellite 31 blades. The blades are attached to a forged 422 stainless steel disc; the blades are secured to the disc by fir tree root fixings. The rotor assembly consists of a front labyrinth ring, first stage blade and disc assembly, spool spacer, interstage labyrinth, second stage blade and disc assembly and the main shaft. The components are fixed to the main shaft by tie bolts. A diagram (Figure 2-58) illustrating the power turbine assembly is included in Appendix 4.

The oil supply to the power turbine is supplied from the alternator module and provides lubrication to the front and rear main radial bearings and the thrust bearing.

The stator casing was originally made of austenitic nodular cast iron alloy, split on the horizontal centre-line to facilitate access to the stator vanes and the rotor. The casings however were prone to severe cracking resulting in a de-rating of the gas turbine for a number of years. In the 1980's new casings were designed, manufactured and installed on both gas turbines. The new casings used an incanol alloy that is less prone to cracking. There have been opportunities to inspect the blading of end B at Stephenville when the gas generator was removed for extensive overhaul in 2000. The Curtiss Wright Power turbines A&B have provided excellent service since the major modifications to the casings. There have been no records of significant problems noted or significant work carried out on the power turbines over the past 12 years.

The elements that could impact on the reliability and availability of the Power Turbines are the blades, discs, bearings, and vibration characteristics. These are somewhat inter-related with uneven deterioration of the blades leading to degradation of bearings and vibration characteristics.

From our review of operations of the Stephenville Facility particularly the minimal running time on the power turbines and our visual examination during the site visit, there is no expectation that the Power Turbines performance will change significantly during the next fifteen years. We recommend however that upon removal of the engine assemblies as noted in sub-section 6.2.1, the Curtiss Wright power turbine assemblies should be inspected in detail to verify the mechanical integrity of the units. In order of priority the following points are recommended to be inspected / refurbished;

- Main line bearings to be removed and inspected.
- Turbine blades to be removed and metallurgical sampling done to verify alloy composition, as well as check wear to the blade roots.
- Turbine disks to be removed and metallurgical sampling done to verify alloy composition and creep growth.

More modern and effective anti-corrosion/thermal protection coatings are available, and are recommended to be applied to the power turbine blades & nozzles to give superior protection/reliability for future operation.

### 6.2.6 SSS Power Turbine Clutches A & B

The SSS Clutch is designed for use between a turbine and an alternator to primarily engage and disengage the gas turbine from the alternator when the alternator operates as a synchronous condenser. When operating for generation purposes the clutch will remain engaged with the alternator. In the case of synchronous condenser operation, the clutch can automatically connect the turbine to the alternator at any speed, with engagement occurring immediately when the turbine speed exceeds that of the alternator. The design accommodates changes in the alignment of the gas turbine and alternator shafts to allow for thermal expansion effects. It acts as a double toothed flexible coupling with tooth surfaces that are designed for low stress and are hardened by nitriding. The clutch is lubricated by oil catchers on the input and output shafts. A dashpot system provides oil to maintain clutch engagement in the event of a reduction of turbine power to the idling mode.

The Power Turbine Clutches A and B were not accessible in the time allotted for inspection during the site visit. A review of available operational history indicates that all problems associated with the clutch assembly have originated with the various sub-systems such as - position indication, brake function and shifting mechanism. All other history indicates satisfactory operation of the clutch assembly itself.

There has been no reported significant work carried out on the Clutches over the past 12 years. The clutch system itself has provided good service and should continue to do so for the next 15 years. There have been a number of problems with the auxiliaries such as the hydraulic system and the position monitoring. These have resulted in difficulties to clutch operations when synchronizing the power turbine with the spinning alternator. It is advised that the components comprising the auxiliaries to the clutches be reviewed for potential replacement with currently available and proven reliability components.

It is recommended that when the gas generator engines have been removed for refurbishment, the drive clutches be completely disassembled and inspected. No major structural problems are anticipated however the brake, position indication and actuation systems should be refurbished and tested to achieve continued reliable operation. It may be prudent to place spare internal components into inventory, as the availability of such parts into the future are unknown and may be cause for concern.

### 6.2.7 Main Power Train Bearings

The major power train bearings were not accessible in the time allotted for inspections. The power turbine and alternator bearings are of the journal, pressure lubricated type. Review of oil sampling results with operational staff indicated no anticipated problems with these bearing assemblies.

### 6.2.8 Main Lube Oil System

The main lube system is a closed loop that incorporates a tank that is partioned internally to allow for entrained gas (air) in the return to evacuate. The tank is large enough to store and maintain oil temperature. Oil is delivered under pressure to the power turbine, clutches and alternator and is returned to the tank by gravity and negative pressure generated by a vacuum fan on the tank.

The oil is moved and pressurized by the lube oil pumps. Constant pressure is maintained in the discharge header by means of a regulating valve which establishes a header discharge pressure of 30 psi (2.04 bars) by sensing discharge pressure after the cooler and filters. The pumps are protected by a relief valve which is set at 100 psi (6.8 bars) and will bypass lube oil in the event of system blockage.

The power turbines, clutches and alternator low pressure lube oil system proper all appear to be in satisfactory condition. The high pressure rotor jacking oil system also appears to be in satisfactory condition.

From the lube oil pumps, the oil flows to an oil/water-glycol cooler. The cooler is a shell and tube type heat exchanger with internal baffles that allows a heat exchange from the oil to the coolant glycol, which is actually a glycol - water solution.

The glycol coolant from the main lube oil cooler is circulated by pumping through a 3-way valve that controls the quantity re-circulated back to the oil-cooler or to the glycol/air heat exchanger (glycol-cooler). As the main lube oil delivered from the oil tank gets warmer, the 3-way valve will operate under the control of its capillary, and will slowly restrict the re-circulating glycol coolant such that the coolant has to pass through the external glycol/air heat exchanger and then back via the 3-way valve where it is mixed with the warmer coolant still circulating, and then to the main lube oil cooler. In this manner, the 3-way valve controls the flows in the coolant sections of the heat exchangers to maintain a steady delivery temperature of oil to the bearings.

The main lube oil system electrical, mechanical and instrumentation equipment is generally in good condition but if certain components such as pumps or fans fail completely, it may be difficult to find the identical item for replacement. The necessary precaution would be to acquire spares for HYDRO to stock. This is particularly relevant to the single glycol circulating pump. It is noisy and should be subjected to a major overhaul. The power plant will be unavailable for operation in the absence of this pump. HYDRO should decide on its requirement for plant availability so that the alternative strategies of installing a back-up pump versus holding a spare pump on site can be compared.

### 6.2.9 Glycol Cooler for Main Lube Oil Cooling System

The external glycol heat exchanger (Photo: SVL-012) is of the finned tube air blast type with its electrically-driven cooling fans and the coolant circulating pump controlled by a sequencer. The main lube oil external glycol cooler assembly is in poor physical condition.

The existing glycol lube oil heat exchanger is constructed of heavy gauge sheet steel frame with support posts and braces fabricated from structural steel angles. At the time of inspection, this equipment was undergoing repairs to the structure to repair damage caused by corrosion. The majority of the joints on this structure were stitch welded together. This detail allows water to enter the joint and promotes corrosion at these locations. The expansion of the steel (rust) as it corrodes causes the steel plate to deform between the welds. In a couple of locations this expansive force has caused some of the welds to crack. However, the main structural members are in acceptable condition.

The repairs being completed entailed; new 3” x 3” hollow structural posts under each end of the fan and motor support channels, re-welding of broken welds and installation of gusset plates. These repairs are adequate to keep the unit operating for the next year. However, the unit should be refurbished within the next couple of years to keep it operational for the next 15 years.

To refurbish this unit for the next 15 years, we recommend replacing the bottom section of the heat exchanger, replacement of the canopy cladding and recoating of the entire structure. The replacement bottom section should be generally similar to the existing bottom of the unit. However, it should be designed to provide for adequate drainage of water and all joints should

be seal welded. The existing bottom can be cut off, motor and fans remounted on the replacement bottom and this new bottom can then be welded into place. The canopy on this heat exchanger is covered with corrugated light gauge sheet steel cladding. Surface corrosion on the cladding was noted in several areas. Therefore, at the time of refurbishment we recommend that this cladding be replaced as well (Photos: SVL-013 & 014).

### 6.2.10 Gas Generator/Power Turbine Enclosures A & B

The gas generator/turbine modules are constructed of structural steel framing with a steel plate exterior cladding. The exterior of the gas turbine modules were recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the gas generator/turbine modules was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

A visual inspection of the gas generator/turbine module supports and welds was carried out and no issues were noted. A visual inspection of the exposed steel structure inside the gas turbines modules was also completed. It was noted that there were some areas in which surface corrosion was present on structural members. These areas were generally small and the corrosion mild and therefore are not a significant concern at this time. However, if this facility is to remain in operation for the next 15 years, the next time the gas turbine equipment is removed for maintenance, we recommend that the interior of the gas generator/turbine modules be cleaned, areas with corrosion sandblasted and the interior of the modules be recoated (Photo: SVL-015).

It was noted that the existing handrails on top of the gas generator/turbine modules do not meet fall protection regulations. The handrails were only 36 inches high and did not have kick plates installed. For fall protection purposes, we recommend that the railings be replaced or modified as soon as possible. New railings should be a minimum of 42 inches high with a handrail, mid-rail and kick plate. Kick plates could also be added to the existing hand rails along with an additional top rail to make the handrail 42 inches high (Photo: SVL-016).

The existing man doors in the gas turbine modules do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow Hydro site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the gas generator/turbine modules. The handrails on the stair landings for these modules also do not meet code as they are not 42 inches in height and do not have kick plates. We recommend that an additional top rail be added to extend the height of the handrail to a full 42 inches and kick plates be added to the bottom of the handrails (Photo: SVL-017).

It was noted that holes in the existing structure for attaching hoist beams and other equipment have been enlarged significantly. We recommend that new plates with holes of the proper size

and location be welded to the existing structures to prevent pullout of bolts during lifting procedures for safety purposes (Photo: SVL-018).

### 6.2.11 Fire Detection and Protection

The fire suppression system consists of Inergen systems located (i) in the turbine enclosure (Module A and B) and the alternator enclosure (Clutch A and B compartments) and (ii) in the fuel forwarding building. There are heat and smoke detectors located at each location.

There is not a fire suppression system located in the control building. In response to a HYDRO request, Stantec provided HYDRO with a preliminary cost estimate for installing an Inergen system in the control building. For protection and insurance reasons, we recommend that an Inergen system be installed in the control building.

The Inergen fire suppression systems are in excellent condition and available for service for an additional 15 years.

### 6.2.12 Gas Generator/Power Turbine Spares

An observation made during the visit to Stephenville, and during inspection of the available outage/maintenance reports provided, is that if additional spare parts inventories were held on-site, the overall reliability of the package could be enhanced. Recommended Gas Generator Engine spares include:

> Fuel injection nozzles: A majority of unscheduled shut downs are caused by high exhaust gas temperature deviation. A spare set of flow balanced fuel injection nozzles would allow mechanical staff to replace defective nozzles with serviceable units, to bring total temperature deviation to within acceptable limits.
>
> Starter assembly: These units are no longer available from the original manufacturer, and are understandably critical to the operation of the package. A spare starter assembly would enhance current and future reliability.

There are companies that hold spare parts and complete gas generators in anticipation of future requirements. We recommend a strategy whereby HYDRO can set up a system of quick replacement if needed. It is unlikely that both gas generators will become unserviceable simultaneously allowing the alternator to be operated as a synchronous condenser or at 50% MW output on one or other gas generator.

## 6.3 ALTERNATOR/EXCITATION SYSTEM

### 6.3.1 Alternator Description

The Stephenville Alternator and Excitation System were manufactured by the Brush Electrical Machines Ltd. of England in 1975. The Alternator was designed to ANSI Specification C50-13. The 13,800 volt, 3 phase 3600 rpm Alternator is an air cooled machine rated at 63,530 KVA at a 0.85 power factor. The Alternator utilizes a rotating brushless type exciter mounted on a stub to the main rotating shaft. The Alternator cooling consists of an external glycol cooler and a 50/50 glycol/water cooling medium to remove heat from the alternator heat exchangers (air to coolant) located at both ends of the alternator. Refer to sub-section 6.3.8 for further details on the Alternator air glycol cooling system.

The Alternator/Exciter is enclosed by a weatherproof, walk-in sound insulated enclosure. The stator is fastened to the enclosure bedplate. The Alternator is enclosed with two end canopies (bulkheads) and a top section canopy. Each canopy is accessible via doors. The alternator enclosure is protected by an Inergen fire suppression system. Refer to sub-section 6.3.7 for further details on the Alternator enclosure.

The alternator's inner stator frame is fabricated from structural steel, welded together to form a rigid structure. The stator core consists of low loss, silicone steel segmental stampings insulated by a layer of varnish on both sides of each lamination. The core is divided into short sections by radial ventilating ducts. The core is bolted to the stator frame. The stator copper winding is of the two layer diamond type with the coils held in open slots by epoxy paper laminate wedges. The two coil layers are separated by epoxy paper laminate wedges. The insulation is Class B synthetic resin bonded mica glass tape. The stator winding laminations are transposed in a regular pattern to minimize circulating currents and losses. The coils are protected against corona formation by coating in the slot length with conducting (graphite) paint and with corona relief paint at each end of the core. The end winding coils are braced with glass cord and densified epoxy paper laminate blocks and supported from the core ends by insulated brackets.

The stator line and neutral terminals are brought out to a cubicle containing the line and neutral bushings. The line bushings are connected to a metal enclosed bus duct system. The Alternator neutral is grounded via a grounding transformer and resistor (refer to section 6.5 for further details on the bus duct, the alternator circuit breaker and neutral grounding).

The rotor consists of a solid carbon steel forging carried in two bearings with a shrunk on half coupling. The field windings are located in slots milled into the rotor forging. The windings are held in place by steel and bronze wedges. Intertooth slots are milled to provide a longitudinal air passage for the cooling air. The windings consist of multi-turn copper coils insulated throughout with Class F mica. The end windings are supported by non-magnetic end caps shrunk on to a spigot on the rotor body and braced with resin bonded asbestos fabric packing

blocks and boxed in with a steel end bracket. Early end caps used 18%Mn / 4%Cr non-magnetic material whereas more current designs use 18%Mn / 18%Cr. The former is susceptible to stress-corrosion cracking. It is recommended that the end caps be closely examined during the refurbishment project.

The alternator and exciter bearings (3) are carried in a fabricated steel pedestal. The housing is split horizontally on the shaft centerline. The bearing is white metal lined and spherically seated. Bearings are lubricated by pressurized oil at 20/30 psig (refer to sub-sections 6.2.7 and 6.2.8 for further details). The oil drain systems operate below atmospheric resulting in air being drawn in through the labyrinth seals providing the necessary ventilation. A high pressure jacking oil system is provided for start-up and shut down purposes.

The stator winding temperature is measured by embedded resistance temperature detectors (RTDs) distributed throughout the windings in the slots. There are 4 RTDs per phase. Alternator air temperatures are measured by thermocouples fitted in the air outlets and inlets from the stator as well as the exciter air outlet. The temperature of the drain oil in each pedestal bearing is measured by an immersed thermocouple. A vibration detector is mounted on the pedestal of each rotor bearing and on the exciter bearing pedestal.

### 6.3.2 Excitation System Description

The main exciter is of the rotating brushless type mounted on a stub shaft which forms an extension of the main drive shaft at one end of the machine and is supported by a third bearing. The brushless exciter was designed to ANSI Specification C50-13. The exciter has stationary field coils and a rotating armature. The exciter field windings are on the stator and its armature is on the rotor. The AC output from the exciter armature is fed through a set of diodes that are also mounted on the rotor to produce a DC voltage. This is fed directly to the field windings of the main alternator which are also located on the rotor. The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings. The Stephenville Gas Turbine utilizes the original brushless exciter and the AVR control system provided in 1975.

### 6.3.3 Alternator/Excitation General Assessment

As noted previously, the configuration of the Stephenville Gas Turbine includes two engines, two power turbines and only one Alternator. This makes the Alternator a critical component in the availability and reliability of the Gas Turbine. An Alternator problem therefore can result in major outages.

While HYDRO personnel have indicated the Alternator and Exciter have generally provided good reliable service at Stephenville, the actual condition of the stator, rotor, exciter and auxiliary components is somewhat unknown. HYDRO was not able to provide documentation,

during the Study, outlining a history of Alternator and Exciter condition testing on this equipment ie data from electrical tests and inspections carried out on the equipment over the years. In order to properly assess the present condition and life expectancy of the Alternator and Exciter, it is very important that data from such tests and inspections, if carried out on the equipment over its years of operation, be current and available for review. Unfortunately, this information was not available. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad. Since this information was not available, such an assessment was not able to be carried out in the Study.

With the type of operation the Alternator has been subjected to over the years – frequent stop/starts and synchronous condenser mode operation (refer to sub-section 2.2) - expectations are that the stator core, stator and rotor windings/insulation, rotor retaining rings and bearings will all show signs of ageing and would be a risk area of concern for available and reliable operation over the next 15 years. HYDRO did not provide any reports on major refurbishment work carried out on the Alternator in the past. This is not to say that there was no refurbishment work carried out. Typical alternator stator and rotor problems that can develop over time from such operation can include:

Potential Alternator Stator Problems

- Stator winding insulation integrity and cracking
- Stator windings -- bar movement, sparking, bulging or puffy coils
- Stator end windings – bar movement, loose/broken bracing and ties, corona (arcing) activity
- Stator wedges – looseness, sparking damage
- Stator core insulation – hot spots. Shorting or low resistances in the inter-laminar insulation may result in abnormal currents, localized heating and iron damage.
- Cracked connections
- Contamination

Potential Alternator Rotor Problems

- Shorted turns and field grounds – occurs when the insulation in the field is damaged. There are a number of factors that can lead to field insulation breakdown/degradation – (i) length of time the alternator has been in service (ii) mode of operation – frequent start-stops (thermal cycling) or base load operation and (iii) contamination introduced into the machine
- Rotor wedges -- looseness, sparking damage
- Thermal sensitivity – is a term used to describe an excessive vibration of the rotor induced by the heating effect of the field current. As field current flows, the copper winding heats up and having a greater coefficient of thermal expansion, expands more than the steel forging. The disparity in expansion transmits forces to the forging through the rotor slots, wedges and retaining

rings. The heat generated in this manner is normally drawn away by the cooling medium (air). Problems can occur when the winding forces act unevenly or when a temperature differential exists across the rotor due to blocked ventilation. These events will cause the rotor to bow somewhat resulting in an imbalance and subsequent vibration.

- Negative sequence events -- operating incidents (closing the alternator breaker when at standstill; single phase operation; transients, etc) that induce heating, arcing within the alternator
- Contamination – problems that arise from contamination buildup on the rotor include low megger readings, overheating and creepage failures
- Forging/retaining ring damage – rotor forgings over time can develop cracking or burning caused by extraordinary events such as negative sequence currents flowing in the forging. Retaining rings are the highest stressed components of the alternator. Alternators operating in cycling modes that require frequent start-stops are susceptible to rotor tooth top cracking. It is generally recommended that rotors that have been in service in excess of 25 years with approximately 5000 start-stops should be inspected for damage.

In the absence of electrical testing and inspection records as well as any major refurbishment work reports on the Alternator over its 30 years of service, it is difficult to determine if any of the potential problems listed above currently exist or might occur in the next 15 year period. In order to determine the present condition of the Alternator and Exciter the following recommendations are proposed:

- A series of electrical tests in line with sub-section 6.3.5 be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above and in order to determine what specific refurbishment work might be necessary on the Alternator in particular, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.

### 6.3.4 Alternator/Excitation Operational and Maintenance Issues

The preceding sub-section listed potential typical and potential Alternator stator and rotor problems that can develop over time. This sub-section will outline problems noted by HYDRO personnel and any refurbishment work carried out on the Alternator in the past

There were reports of the operation of a negative sequence relay on start-up on several occasions. This was attributed to possible faulty settings of the relay. This may indeed be the reason; however, it is likely the relay detected a negative sequence event. Negative sequence currents can lead to rotor forging and retaining ring damage.

There are reported incidents of vibration alarms occurring on the exciter end of the Alternator on start-up. The reason for or cause of the vibration alarm has not been identified to date. This alarm could be caused by a number of factors – (i) faulty vibration detector (ii) shorted turns in a field coil (iii) rotor balance issue (iv) shaft alignment issue or (v) bearing issue.

As noted previously, there were no reports provided by HYDRO on any major refurbishment work that may have been carried out on the Stephenville Alternator over the past 30 years. This does not necessarily mean that no major refurbishment work was done. It could also be due to the fact any such reports could not be found.

Hydro does have plans to replace the existing original excitation AVR control system at Stephenville with an AVR similar to what was installed at Hardwoods in 2006.

### 6.3.5 Alternator/Excitation Testing Program

In order to assess the condition and life expectancy of the Alternator and its Excitation System, it is important that electrical tests and inspections be carried out on a regular interval basis (annually; semi-annually; etc) over the years and the data recorded. A comparison of the test results taken over a period of time will usually indicate trending patterns good or bad.

The following types of electrical tests are often carried out on an Alternator and Excitation System as part of ongoing inspection and maintenance programs:

Stator Electrical Tests

- EL-CID tests --- detects problems in the stator core especially interlaminar insulation defects (hot spots)
- Partial Discharge Test --- detects stator winding insulation deterioration
- Polarization Index Test --- tests the insulation resistance to ground
- Hi-Pot Tests --- Insulation test
- Megger Tests at 1000 or 5000 V DC
- Thermocouple tests/calibrations
- Inspection and tests of Alternator bushings

Rotor Electrical Tests

- Megger Tests at 500 V DC -- detects rotor winding insulation deterioration/ contamination
- Rotor winding resistance measurements

Bearings Electrical Tests

- Megger tests to indicate general cleanliness of bearing pedestal and insulation resistance
- Thermocouple tests/calibrations

Excitation System Electrical and Operational Tests

- Exciter rotor and stator winding resistance measurements
- Polarization Index measurements and Megger tests to determine condition of the exciter rotor and stator winding insulation
- Thermocouple tests/calibrations
- Diode checks - measurement of diode forward and reverse bias resistance and voltage drop; resistance of fuses; etc
- Operational checks on the AVR

The following Alternator visual inspections are often carried out as part of ongoing inspection and maintenance programs. These inspections, carried out during major outages with the Alternator removed from the Unit, can assess the condition of the stator, rotor and bearings. Items typically inspected during major outages are as follows:

Stator Visual Inspection

- Loose or damaged wedges;
- Loose or cracked or failed connectors;
- Dusting, greasing and other signs of movement of windings;
- Indication of arcing (hot spots); damaged laminations;
- Loose Core bolts;
- Signs of contamination / excessive dirt

Rotor Visual Inspection

- Signs of physical damage;
- Loose or cracked or failed connectors;
- Slot wedge migration and possible contact with retaining ring;
- Signs of overheating;
- Loose rotor wedges;
- Dye penetrant examinations and magnetic particle tests on forgings, retaining rings and fan components to detect fatigue cracks; ultrasonic examination of interior surfaces of the forging and retaining rings

Bearings Visual Inspection

- Assess general condition of the bearings
- Do the bearings require re-babbiting or machining?

HYDRO provided copies of its Gas Turbine daily, weekly, semi-annual, annual and 5 year inspection check lists as well as the 6 year P&C inspection check list. Most of these inspection check lists were dated 2003. There is essentially no reference to alternator and exciter tests or

inspections on these lists. Copies of these lists are included in Appendix 5. In addition, there are Alternator and Exciter tests and inspections listed in the O&M Manuals for each site. It is not obvious that any of these recommended tests and inspections are being carried out by HYDRO.

On a go-forward basis, it is recommended that a regular formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the above listed tests and inspections are part of that program. The electrical tests should be conducted on an annual basis with major visual inspections on a 5 year basis. The test data and inspection information should be recorded and stored at a central location for easy access in the future. In addition, a specific group at HYDRO should be charged with the responsibility for conducting such tests and inspections.

### 6.3.6 Alternator/Excitation Recommendations Summary

- It is recommended that a series of electrical tests be carried out on the Alternator at the earliest opportunity to provide a snapshot on the current condition of the Alternator.
- In addition to the electrical tests noted above, it is recommended that the Alternator itself or as a minimum the rotor be physically removed from its enclosure and the visual inspections and electrical tests noted above be carried out. This detailed examination will clearly determine the condition of the Alternator and its components and the specific refurbishment work (if any) that must be carried out to ensure its ability to operate reliably for a further 15 years.
- The Curtiss-Wright Turbine-Alternator Manual (Book 3) recommends a minimum list of spare parts that should be carried for the Alternator and its Excitation System. It is recommended that the suggested list of spares be stocked at one central location for both the Hardwoods and Stephenville sites.
- On a go-forward basis, it is recommended that a regular (annually; semi-annually; etc) formal inspection and test program be established for the Alternator and its Excitation System and that some or all of the tests and inspections listed in sub-section 6.3.5 be part of that program.

### 6.3.7 Alternator/Excitation Enclosure

The alternator module is constructed of structural steel framing with a steel plate exterior cladding. It is our understanding that the exterior of the alternator module was recoated approximately one (1) year ago. The exterior coating was found to be in good condition and no corrosion was noted. The concrete foundation under the generator module was visually inspected and was found to be in acceptable condition with no visible cracking or significant deterioration.

The interior structure of the alternator module was also reviewed. This module contains a great deal of equipment and access to structural members was quite limited resulting in the inspection of this module being also limited. No structural issues were noted.

The roof of the alternator module requires access from time to time for repair and maintenance activities; however, the roof of the existing generator module is over 10'-0" high and currently does not have any handrails. Therefore, this area does not meet fall protection and safety regulations. There are several existing eye-bolts attached to the roof of the generator module that may be adequate as fall arrest anchors; however, they are not close enough to immediately tie to once you have climbed to the roof level and are spaced far enough apart that HYDRO staff may have to unhook and hook to move to different areas of the alternator roof. It is important to note that no structural analysis has been carried out by Stantec to determine the capacity of these anchors for fall arrest purposes. We recommend that proper handrails be installed on the roof along the north and south sides of the alternator module for fall protection purposes (Photo: SVL-019).

The existing man doors in the alternator module do not have any windows. We recommend that windows be added to the doors for safety purposes. This will allow HYDRO site personnel to view the interior of the module before opening the door. This would be particularly helpful should there be a fire inside the alternator module. The handrails on the stair landings for this module also do not meet code as they are not 42 inches in height and do not have kick plates. We recommend that an additional top rail be added to extend the height of the handrail to a full 42 inches and kick plates be added to the bottom of the handrails.

### 6.3.8 Alternator Air Cooling System

The alternator cooling system uses a 50/50 glycol-water mixture to absorb heat from the air circulating inside the alternator casing and to discharge the heat to ambient air by means of an external heat exchanger complete with fan cooling.

Inside the alternator, air is passed through the air-gap behind the stator end windings and under the rotor winding. The space behind the stator core is divided into inlet and outlet compartments and air passes via radial ducts in the core to and from these compartments to the air-gap. Air from under the rotor windings flows through vents in the rotor surface in line with the outlet compartments of the stator core.

Under normal conditions, air is passed through a glycol/water finned tube heat exchanger (Photo: SVL-020) and circulated back to the machine. The glycol/water is pumped to an external heat exchanger where fans blow ambient air over a nest of finned tubes to cool the glycol. There are two glycol/water pumps for this system and two fans for the external heat exchanger.

At the time of our visit, the glycol cooler had been taken out of service. The alternator was being operated with the access doors to the canopy above the alternator wide open to allow circulation of unfiltered ambient air in the alternator. Open doors, in addition to allowing contaminants to enter the generator enclosure, may compromise the Inergen fire suppression system. It was reported that an alternator high temperature alarm had come up during recent operations and while the cause of the alarm has not been identified, there is concern that the glycol/air heat exchanger may be unable to dissipate sufficient thermal energy. High temperatures in the alternator have been the source of shutdowns in the past. HYDRO will commence investigations to determine the cause of the high temperature alarm.

The cooling system should be capable of dissipating about 5GJ/hour during the highest ambient temperatures, say 30$^{o}$C. Calculations by Neill and Gunter, using test data provided by HYDRO, suggest that the external cooler is operating at about 67% of its design capacity. If this is indeed the case, there is a limit on the maximum output (MW) that the unit can provide on a continuous basis. The limit is a function of the ambient temperature.

The finned tubing of the external heat exchanger was observed to have a grey dust coating on the fins. This will impair heat exchange, and it is proposed that a test be undertaken to measure temperatures of coolant in/out, and air in/out of the external heat exchanger. Also, if possible, a means of measuring the flow of coolant should be devised. These data can be used to calculate the capacity of the exchanger, and to establish the improvements achieved by cleaning the external fins.

Similar data should be collected for the heat exchanger inside the alternator casing to verify that it is still operating at or near design conditions.

The external glycol cooling heat exchanger is constructed of structural steel columns, braces and framing. The exterior of the heat exchanger and the canopy of the heat exchanger are clad with heavy gauge steel plate.

Surface corrosion on the main structural steel framing members was noted in several areas. However, this corrosion was generally light and the steel framing members were found to be in acceptable condition.

The heavy gauge exterior cladding on the heat exchanger and the canopy was stitch welded to the structural steel framing. Over time water has entered the joints between the cladding and structural framing which were not welded and this has resulted in corrosion of the steel at these locations. The expansive forces created by the steel turning to rust has caused the heavy gauge steel cladding to deform along the panel perimeter between the stitch welds.

Given the level of deterioration, we recommend that the heat exchanger support system be recoated within the next two (2) years if it is to remain in service for the next 15 (15) years. At that time, the existing cladding should be removed and replaced with new heavy gauge sheet

steel. All joints between the cladding and structural framing should be seal welded to minimize corrosion at these joints in the future (Photos: SVL-021 & 022 & 023).

The cooling equipment itself should be adequate for a further 15 years, subject to the refurbishment to the structural components noted and the resolution of the alternator high temperature alarm (if a glycol cooler problem) being rectified by cleaning the tubes and external fins. This also assumes that a maintenance schedule is put into operation that provides for cleaning the tubes regularly.

Instrumentation on the alternator cooling system appears in good working order. There have been no significant instrumentation problems in the last year and a half. At the time of the site visit, the coolant had been drained and the low level switch did not operate. There may have been some coolant left in the tank. The operator was to verify at a later time.

## 6.4 FUEL OIL SYSTEM

### 6.4.1 Fuel Unloading and Storage

The Gas Generator Engine fuel is No. 2 diesel oil which is delivered to the Site by truck. The trucks are unloaded via pumps at the Fuel Forwarding Building. Fuel storage comprises three interconnected storage tanks each with 126,000 nominal gallons capacity (477,000 litres) (Photo: SVL-024). At 50 MW, the plant will use about 16,000 L/hour, so one tank lasts approximately one day. All three storage tanks contained oil at the time of inspection. Therefore, only visual inspection of the exterior of the tanks was carried out.

The tanks were built to API Standard 650, and should be operated subject to API Standard 653 – Tank Inspection, Repair, Alteration and Reconstruction. This standard calls for periodic inspections and records of construction, inspections, and repairs. The frequency of inspections can be linked to a rate of corrosion or in the absence of measurements the frequency of inspection must be less than every ten years.

The tanks have been in service since 1977. The tanks were inspected in 1999 by *fga*-CANSPEC (Reports provided by HYDRO) in accordance with API 653 -1995. The tank shell was found to have no internal and external corrosion and no areas of pitting or weld attack. Inspections of the tank floors consisted of magnetic flux leakage scanning and a systematic ultrasonic thickness survey. The remaining useful life of the tank floors as estimated by fga-CANSPEC are as follows: Tank 1 (16 years); Tank 2 (8 years) and Tank 3 (15 years). The roof and roof rafters on all tanks were found to be in good condition. All tanks were deemed to be meeting the requirements of API 653-1995. It is recommended that HYDRO conduct within the next 2 years a further detailed inspection of the tanks and in particular an ultrasonic thickness survey of the tank floors.

As part of the tank inspection program, HYDRO refurbished the tanks – interior cleaned, floor painted; reshaped the dyke, installed a new dyke liner throughout and installed new piping within the dyke area. The exterior of the tanks was painted in 2004.

From an external observation, the tanks appear to be in good condition and should be serviceable for a further 15 years use.

The exteriors of the fuel storage tanks were recoated approximately three years ago. This coating was found to be in good condition and no signs of surface corrosion were noted during the inspection. As well, no significant pitting due to earlier corrosion was noted during the inspection. In general the exterior of all three fuel storage tanks were found to be in good condition.

All three tanks have proper ladders with climber safety systems. The climber safety system consists of a rigid rail attached to the rungs of the ladder at equal intervals. Fall arrestors, lanyards and harness are fastened to the climbers for fall arrest. The ladders were generally in good condition. However, HYDRO site personnel indicated that three (3) rungs at the top of the ladder of tank “35b” are missing welds on the inside of one rail. We recommend that these rungs be welded and the area affected by welding recoated.

The landing platforms on the top of the tanks were found to be in good condition and had proper handrails installed. As well, a static fall arrest lifeline has been installed between the landing platforms at the top of the ladder and the vent stack in the centre of the tank.

Each storage tank is fitted with a float and tape level gauge, a conductivity level switch, a differential pressure level transmitter, a temperature gauge and two grounding cables. All instrumentation equipment appears to be in good working order.

It is our understanding that the containment dyke containing the three (3) oil storage tanks was replaced approximately three (3) years ago. At that time, HYDRO reported that a liner was installed, and the dyke was covered in gravel.

The dyke was found to be in generally good condition at the time of inspection. Three (3) of the dyke walls were in very good condition and the slopes are holding up well. However, the north wall of the dyke facing the fuel forwarding building did appear to be lower in elevation than the other three (3) dyke walls. As well, the slopes of this wall were not in as good a condition as the other three walls. The lower elevation of the wall allows water from the site to drain into the dyke. This combined with site personnel walking down the slopes of this dyke wall to access the oil storage tanks have resulted in some deterioration of this dyke wall. We recommend that the top of the dyke wall be raised to the same elevation of the other three dyke walls to prevent runoff from entering the containment dyke. Also, installation of access stairs on the north side of the dyke will help prevent slope deterioration caused by site personnel walking down the slope of the dyke (Photo: SVL-025).

A drainage pipe with a manually operated valve in the south-west corner of the property is currently used to drain the fuel storage containment dyke. The containment dyke is adequately graded to this outlet pipe. At the time of inspection, there was approximately 12 inches of water over the top of the outlet pipe. We recommend that site personnel regularly drain the containment dyke to help prevent buildup of excess water in the dyke and help prevent premature rot of the timber posts supporting the access platform for the outlet pipe. The bottoms of the tanks are elevated approximately two to three feet above the bottom of the dyke to prevent submergence in water and corrosion. As well, it was noted that a light standard has been installed on all four sides of the containment dyke and should provide adequate lighting for the tank lot.

During the inspection it was noted that the containment dyke liner around several of the round concrete pilaster pipe supports inside the dyke were not sealed and could allow leakage should a spill occur. In these locations, the clamps holding the liner in place are loose and the caulking around the top of the liner has failed. We recommend that the clamps around all concrete pilasters be retightened and caulking reapplied to the joints where necessary (Photo: SVL-026).

It was noted that the containment dyke liner was not visible around the concrete block surrounding the oil transfer piping entering the ground in the north-west corner of the dyke. It is therefore possible that there is not a proper seal between the concrete block and the containment liner. We recommend that an investigation be carried out to determine if the joint between the concrete block and the containment liner is adequately sealed (Photo: SVL-027).

### 6.4.2 Fuel Forwarding

The function of the fuel forwarding module is to provide fuel at a positive and constant pressure to the gas generator engines for combustion. An inspection was made of the fuel forwarding equipment contained in a building integrated with the spill containment dyke surrounding the tanks. The major equipment located inside the building consisted of the main pump and motor, the off-loading fuel pump and motor, the auxiliary fuel pump and motor, the electric fuel heater, fuel filters, pressure switches, control valves, regulator valve and the associated piping.

The pumps, valves and piping were checked for evidence of problems. Nothing significant was found and the equipment had a well cared for appearance. There is sufficient back-up pumping and valving to provide a low risk of failure to deliver fuel. However, there is only one fuel heater and a spare replacement element should be carried together with the necessary gaskets, etc.

The fuel forwarding area contains a motorized valve with position indication in each of the three fuel lines coming from the storage tanks. A local control panel permits the operator to select one of three tanks as a supply. The panel also contains the instrumentation for tank level alarms, including local annunciation for tank overfull. A common fuel line contains a recently installed Coriolis meter for accurate measurement of fuel consumption. A heater preheats the fuel. As well, a single filter is installed in-line within the common line.

All instrumentation is in good working order with the exception of the differential pressure switch on the fuel filter. This switch has had its sensing lines removed. HYDRO has opted to change the filter on a schedule correlated to fuel consumption. It is suggested that the differential pressure switch remain in service in case maintenance cycles are missed or the filter clogs more quickly than expected.

### 6.4.3 Fuel Piping

The installed system of above ground interconnecting piping and valves from the fuel forwarding building to the storage tanks allows for any combination of tanks to be filled or drained simultaneously. The condition of the piping system is good and should be reliable for a further 15 years of service.

The piping from the fuel forwarding building to the storage tanks is above ground. The piping from the fuel forwarding building to the power plant is underground and does not conform to current codes. HYDRO is currently replacing this piping with double-walled piping with vacuum monitoring. The interior pipe is 4 inch and the exterior pipe is 6 inch.

## 6.5 ELECTRICAL SYSTEMS

### 6.5.1 13.8 kV Switchgear

The switchgear serves to isolate the plant and its related systems electrically from the grid when it is not running or is down for maintenance. The switchgear and associated protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions.

Switchgear is subject to deterioration over time due to breaker contact wear, arcing damage and insulation breakdown. A typical switchgear installation includes integral instrumentation transformers, which are also subject to insulation degradation. While generator breakers are infrequently called upon to interrupt heavy or short-circuit loads, the recommendations of the manufacturer should be followed with respect to inspections and maintenance schedules.

Switchgear should be replaced when no longer supported by the manufacturer, parts availability wanes and safety of personnel or equipment potentially becomes compromised as a result.

The 15 KV 3000A metal-clad walk-in switchgear assembly houses the 13.8 KV alternator circuit breaker, potential and current transformers, station service power fuse and the disconnect switch. HYDRO provided a copy of a report on a condition assessment of the Hardwoods and Stephenville 15 kV Switchgear and outdoor Bus Duct carried out by Acres in 1995. It is our understanding that most of the recommendations outlined in that report have been carried out. A new 15 kV metal enclosed switchgear assembly was installed in 1998. Switchgear & Controls Ltd, Markham Electric supplied the complete assembly. The alternator breaker, a withdrawable

vacuum type breaker, was replaced in 1998 because of a short circuit developed at the bus duct. While a detailed inspection of the switchgear was not carried out in this study, the physical condition of the switchgear and the associated equipment appears to be in good condition. The typical operating life for switchgears and breakers could be assumed to be 35 - 40 years. With regular maintenance, the switchgear and the breaker should be able to operate normally for another 15 years or more. Replacement parts and services can be expected to be obtained locally or though switchgear equipment suppliers.

A regular maintenance program for the switchgear and its equipment should be followed. Attention should be paid to inspect the condition of the breaker contacts, check for arcing damage, check the operating mechanism of the breaker and conduct insulation tests for insulation breakdown.

The disconnect switch should be operated occasionally and a set of spare power fuse should be stored at site or readily obtainable upon emergency replacement.

HYDRO should apply infrared thermography to monitor temperatures and thermal patterns while equipment is running in full load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. Arc flash labels should be posted at the switchgear cubicles to provide guidelines on personal protection equipment requirements. Another option is to install infrared scanning ports to allow scanning without opening the door.

A rain shield should be installed at the air vent to prevent rain and snow blowing into the switchgear enclosure (Photo: SVL-028).

The delivery time for a replacement switchgear and breaker could be in the area of 20-24 weeks. A back-up plan should be prepared to cater for a total failure (for example a fire) of the switchgear and/or breaker.

### 6.5.2 13.8 kV/600 V Station Service Transformer

The 750 KVA, 14.4 KV-600V dry-type transformer located inside the switchgear building enclosure appears to be in good physical condition. Results of tests carried out on the transformer over the years were not available for review during the visit. With regular maintenance and adequate ventilation, the transformer should be able to provide satisfactory service for the next 15 years.

The transformer and its accessories, such as the lightning arrestors, the surge capacitors and the cable connections should be part of a regular maintenance program. HYDRO could apply infrared thermography to monitor temperatures and thermal patterns while the transformer is running under load to detect changes in temperature. Repair and/or replace any hot-spot area. Safety procedures must be observed during scanning because the enclosure doors will be

opened for scanning. Arc flash labels should be posted at the transformer cubicle to provide guidelines on personal protection equipment requirements.

The transformer insulation should be tested at regular intervals. Temperature inside the transformer cubicle should be monitored and additional ventilation may be necessary if the room temperature is too high. Over heating and overloading of the transformer will shorten the life of the transformer.

### 6.5.3 13.8 kV Bus Duct

The 13.8 KV metal enclosed non-segrated bus duct (Photos: SVL-029 & 030) connects the alternator phase bushings to the 13.8 kV alternator circuit breaker located in the 13.8 kV switchgear enclosure. The bus duct further connects the circuit breaker to the unit step-up transformers 13.8 kV bushings located in a low voltage termination box mounted on the transformer. The bus bar material is copper and the bus duct is enclosed. Two (2) sections of bus between the alternator bushings and the switchgear assembly and between the switchgear and the step-up transformer were replaced in 1998 due to a reported short circuit between two phases. The robust bus duct metal enclosure was replaced at the same time. With regular maintenance, the bus duct should be able to provide satisfactory service for the next 15 years.

Regular maintenance should include inspection for bus bar rusting and corrosion, insulator tracking and the physical appearance of the enclosure. The bolts at the joints should be re-torqued regularly. Infrared scanning of the bus bar, the joints and the terminations should be performed to identify hot-spots.

The bus duct at Stephenville has a history of corrosion and rusting. If it is necessary to replace the bus duct, cable duct should be considered. Cable ducts are gaining popularity over bus ducts because of their flexibility, and easier and cheaper to install. Providing that the design and specification of the cables are done correctly, cable duct may have less chances of having a phase-to-phase or phase-to-ground flash over caused by moisture penetration or moisture condensation inside the duct than non-segregated bus.

### 6.5.4 AC and DC Motor Control Centres

The motor control centres (MCC) provide protection and control for the auxiliary electrical devices for the gas turbine plant. There are two motor control centres - one for the 250V DC equipment and another for the 600V AC equipment. The MCC cabinets house the basic electro-mechanical devices such as circuit breakers, contactors and overload relays. The original MCCs were supplied by Westinghouse. Eaton/Cutler Hammer took over the MCC product lines from Westinghouse. Eaton/Cutler Hammer or other electrical equipment distributors can supply compatible replacement parts or replacement kits for any MCC up-grades. The operating handles of the MCC are capable of padlocking. This feature should satisfy HYDRO's locking and tagging requirement.

Unless the operating philosophy of the motor control changes drastically, such as operating the motors with variable frequency drives (VFD), adding feedback monitoring and network interfaces that would require changes to the structure of the MCC wrappers (any changes to the MCC structure will require CSA re-certification), the existing MCC should not require to be replaced and should be capable of operation for a further 15 years.

In addition to regular inspection on the de-energized equipment, infrared thermography inspection should be performed on a regular basis with the equipment energized. Safety procedures must be observed during scanning because the enclosure doors will be opened for scanning. Arc flash label should be posted at the MCC to provide guidelines on personal protection equipment requirements.

### 6.5.5 DC System – Station Battery and Charger

The station DC system has to provide sufficient capacity to supply the various DC motors and DC powered protection and control systems.

Depending on the battery type, the station battery is subject to various forms of deterioration including: corrosion of posts, cables, hold-downs, and battery trays; cell damage due to severe discharge or overcharge conditions; high resistance connections; and reduced cell capacity. Routine maintenance will serve to detect and remedy these conditions, such that replacement is only required when the general condition deteriorates beyond the point that maintenance is ineffective or overall battery capacity no longer meets the plant requirements. Manufacturers typically specify a design life of 15 to 20 years for wet-cell type batteries, and recommend that the banks be replaced after this period of time.

Common charger and inverter failures include open or shorted rectifier diodes or deteriorated electrolytic capacitors. Replacement is a consideration if vendor support is no longer available, improved output characteristics are desired (i.e. reduced ripple, improved regulation) or the charger or inverter load changes considerably due to changes in the station.

There are three banks of batteries (125 Vdc and 250 Vdc) inside the battery room. The 125 V battery bank was replaced in 2005. The battery cells are in good condition. No leaks or cracks are visible. With regular maintenance, the batteries should be able to last for more than 15 years. The 250V and 125V chargers are Power Tronic, Type 668, Class “D” chargers (Photo: SVL-031). They are no longer being supported by the vendor.

The original inverter was supplied by CTS Canada. It failed and was replaced with a unit supplied by Pylon in 2004. Under normal operating conditions, the inverter should be able to provide satisfactory service for the next 15 years.

The regular battery and charger maintenance program should be followed. Defected cells/parts should be repaired or replaced as soon as they are detected. Re-assess the rating of the

batteries and charger if there is a major addition of DC loads. A replacement program should be prepared to replace the chargers as the opportunities arise if the vendor does not continue to support the service of this type and model of charger anymore. The batteries should be able to operate satisfactory for the next 15 years.

### 6.5.6 Protection Relays and Synchronizer

The protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. Their functions must be sufficient to protect the generating unit against all harmful conditions that may develop and act quickly and appropriately to isolate the abnormal conditions from the system and the alternator. The synchronizing function is critical and requires accurate and reliable monitoring of voltage level, frequency and phase angle. It ensures bump less transition of the alternator to the on-line state, thereby minimizing machine stress and power system transients.

The measuring relays for the alternator protection system are electromechanical relays (Photo: SVL-032). For electromechanical relays, ageing of the moving surfaces (such as bearings and bushings for induction discs) due to corrosion or excessive wear can lead to failure of the relay. For measuring relays, ageing of components such as capacitors, resistors, coils and worn contacts are sources of failure. Ageing mechanisms include: corrosion and overheating of contacts; vibration on bearings; wear of bearing surfaces that have exceeded the number of design operations; and failure of insulation material in capacitors and other components due to ageing of the materials.

While a detailed alternator protection review and analysis is not within the scope of this study, a review comparing the existing protection functions with IEEE Std. C37.102-1995 IEEE Guide for AC Generator Protection is provided as follows:.

<u>IEEE recommendations:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 87GN, 51/59GN)
- Field fault (64F)
- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59, 27)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)
- Alternator turn to turn fault (61)
- Voltage balance (60)

<u>Existing Protection Functions:</u>

- Loss of excitation (40)
- Phase and ground fault (87G, 64G)
- Field fault (64F)

- Unbalanced current (negative sequence) (46)
- Over and under-voltage (59G, 27G)
- Over and under frequency (81)
- Stator thermal (49)
- System back-up (51V)

The existing protection provides adequate basic protection functions to protect the alternator. Compared with the IEEE Standard, the functions that are missing are the generator turn to turn protection (61) and the voltage balance relay (60). An alternator turn to turn fault is difficult to detect. Alternator differential relay will provide protection for alternator internal faults. Depending on the setting sensitivity of the alternator differential relay, it will provide some degree of turn to turn fault protection. The function of the 60 relay is to block the mis-operation of the relays using voltage as a restrain source. There will be costs to incorporate these two functions into the existing protection system. HYDRO's protection design engineer may want to review the scheme and decide whether the level of reduced risk will warrant the level of expenditure required.

Although the existing relays could provide adequate protection, the availability of any direct replacement of the electromechanical relays will be limited. Unless HYDRO has spare relays stocked in their system, it will be difficult or even impossible to obtain direct replacement relays from the manufacturers. The option of replacing the entire protection panel with digital protection relays should be considered because of the ageing considerations of the electromechanical relays, the unavailability of the replacement relays and the increased protection obtained through the multiplicity of advanced functions available in today's digital relays at relatively low cost.

The automatic synchronizing function is provided by the Bailey DCS system. The sync-check relay, PRS-250 is provided by Basler Electric. The design of the sync-check relay has not been changed for the last 15-20 years and is expected to remain that way unless a parts availability issue forces Basler to make a component change.

Historically, the failure rate of electromechanical relays is low (with good maintenance, some of the relays are still in service after 40 years or more) but some of the relay components will age and will fail eventually. The replacement parts and the skilled technicians that are knowledgeable enough to fix these relays are getting harder and harder to find. We suggest that a protection replacement budget and protection modification program should be prepared for the Facility. Replace the relays for the Facility when the opportunity arrives and possibly keep the replaced relays as spare for the other Facility for direct replacement.

With today's technology, one multifunctional digital protection relay could replace several electro-mechanical relays to provide the same protection functions. The GE Multilin Generator Protection Relay replaces the following existing protection functions – 40, 64,87G, 46,59,27,81, 49 and 51V (refer to relay function numbers above). A cost estimate has been provided for one

multi-functional digital generator protection relay. If HYDRO's protection philosophy requires additional relays for backup or for another redundant scheme, the cost estimate will increase accordingly.

In the meantime, considering the age of the relays and the non fail-safe design of the electromechanical relays, it may be prudent to test the existing relays in a 2 or 3-year cycle rather than the 6-year cycle as recommended in the HYDRO maintenance program. In conversation with Craig Warren (HYDRO P&C Engineer), he indicates that more than once, the negative sequence relay operated immediately after the unit was put on line. We recommend the setting of this relay be reviewed and the relay tested and re-calibrated if necessary.

### 6.5.7 15 kV Power Cable

The power cables associated with the 750 kVA station service transformer (Photo: SVL-033) are cross-linked polyethylene (XLPE) insulated cables.

Medium voltage XLPE insulated cables were first installed in the late 1960's. The cable manufacturers and utilities expected the cables to perform reliably for 20-30 years. History has shown that the service life of some of these early cables was far shorter than expected. Many cables failed after only 10-15 years in service. It was later discovered that voids and contamination in the semi-conducting shields, as well as other design and manufacturing deficiencies, led to voltage stress concentrations within the cables. The elevated voltage stress, combined with moisture ingress into the cable structure created what are known today as water trees. These microscopic cavities degraded the insulation over time, ultimately causing the cable to fail. To reduce water tree growth, a special engineered insulating material designed to limit water tree growth called XLP-TR was commercialized in the early 1980's and has been performing reliably in service for over 20 years. Furthermore, the design, manufacturing practice and quality control of power cables have improved drastically within the last 20 years. The design life for the XLPE insulated cable is 20-25 years. The design life for XLP-TR (trees retarded) insulated cables is 30 years or more.

It is our understanding that the 15 kV power cables in the Plant were the original installations that dated back to 1975. The failure rate for power cables installed before early 1980s is high. Our recommendation is to replace the 15 kV power cables installed during 1975 with XLP-TR type insulated cables during the next major Plant shut down. For a 13.8 KV system, the power cables should be shielded and terminated with stress cones.

### 6.5.8 Motors

Properly selected and installed motors are capable of operating for many years with a reasonably small amount of maintenance. Routine maintenance should include inspection for dirt, corrosion, heat, noise, vibration and brush conditions; lubrication of bearings; measuring and trending of the winding insulation.

Motors located inside the buildings seem to be in good physical conditions. The motors located outside are covered with fine dust and show sign of corrosion. All motors should be cleaned, check for signs of corrosion, perform internal inspection, and open the conduit box to check for deteriorating insulation or corroded terminals. Insulation resistance (Megger) test and Polarization Index test should be incorporated into the maintenance program. Any damage parts discovered during inspection should be repaired and rebuilt. Well maintained motors should provide satisfactory service for the next 15 years.

### 6.5.9 Emergency Backup Diesel Generator

An emergency backup diesel generating unit was installed in 2005. The diesel generator was relocated from another HYDRO site. The diesel generator is a self contained package consisting of control panel, battery charger, etc. The 40 kW 600 volt AC diesel generator starts automatically on loss of the AC station service supply to the Gas Turbine and supplies power to a backup battery charger which in turn ensures the integrity of the 125 Vdc supply to the Gas Turbine for protection and control purposes. The diesel generator also provides a backup AC supply for one of the air compressors. The diesel generator is in excellent condition.

## 6.6 CONTROL AND INSTRUMENTATION SYSTEMS

### 6.6.1 Control Module

The gas turbine control module features an ELSAG Bailey INFI 90 DCS installed in 1999 to replace a mainly electromechanical relay control system. The DCS system incorporates three subsystem hot-swappable controllers with redundant backup controllers. The DCS internal network utilizes a redundant communication module. The operator interface uses a PC running PCV and QNX software. The PC is connected to a color screen which displays system graphics and to a keyboard for operator input. A communication link connects the PC to a SCADA system which allows remote control and monitoring of the gas turbine from the Energy Control Center in St. John’s, Newfoundland.

There have been some failures recently of input channels. Stantec has requested a report from HYDRO on the number of failures and the availability of spares. It appears that there may be no spares since the operator has rewired the inputs from the failed channels to channels which are working, rather than replace the faulty input module itself. ABB still sells these input cards and will support them for an additional 10 years once the product has been discontinued. In addition, newer technology is available that will directly replace the older technology and use the same footprint. Stantec recommends replacing faulty modules since the failure of one or more channels could be an indication that other channels are soon to fail.

The interface computer (PC) was out of service at the time of the site visit due to a motherboard failure. There have also been video card and hard drive failures in the past. A similar PC from the operator’s home is temporarily replacing the interface computer. The interface computer is

an older vintage and as such has very little memory capacity and will not run today's software. There is significant risk in not replacing the existing PC since it is older technology and does not have a ready availability of parts. ABB has issued a quotation to HYDRO P&C (copied to Stantec) for a new PC with the latest PCV and QNX software. The new PC will also give HYDRO the ability to do more extensive trending. Stantec strongly recommends the PC and software upgrade be implemented.

The power supply system for the DCS is obsolete. Stantec recommends replacing the power supply system in order to extend the life of the control system out 15 years. ABB has provided a quotation to HYDRO P&C (copied to Stantec) for a new power supply.

Conditions in the control room were quite hot and humid at the time of the site visit. In addition to the hot weather during the site visit there are also many sources of heat in the room. Heat and humidity are known to speed the deterioration of electronic components. Stantec recommends the installation of an air conditioning unit in the control equipment room.

### 6.6.2 Interposing Relays

In August 2006, P&C staff discovered a problem with the control system design. There were at least 8 relays with contact that were not rated for the current which was being interrupted. The problem was detected when welded contacts were found on the relay which controls the fuel recirculation valve. Pitting and carbon deposits may have been forming on some or all of these relays resulting in increased switch bounce and high impedance contacts. High impedance contacts would cause in a reduction of power to the device being controlled. Partial welding would result in late break operation. The overall result of using the incorrect relays could have been inconsistent control, possibly with shutdowns or non-starts.

### 6.6.3 Vibration Monitoring

The existing vibration monitor by IRD was installed in 1975. The monitor appeared to be functioning well at the time of start up during the site visit. Vibration was a little high on the lower speed range but dropped down as the speed was increased.

Some vibration problems (non specific) were reported in 1993 but the actions were not recorded in the Station Log. There were no further problems recorded until 2007; however, some of the alternator trips in the log are not descriptive and could have been caused by vibration problems or vibration monitoring equipment faults.

In April 2007 the alternator exciter was giving a vibration trip. Initial troubleshooting seemed to indicate the accelerometer was at fault but continued testing included a shaker table test indicated that the accelerometer was calibrated correctly. There was a true vibration issue, not a faulty monitoring problem.

Operations staff and P&C are of the opinion that the vibration monitoring equipment needs to be replaced. Stantec has not seen evidence of troubleshooting activities which support the conclusion that the monitoring equipment is faulty. That having been said, the equipment is obsolete and could fail during the next 15 years. According to P&C staff, HYDRO has an approved capital budget item to replace the existing vibration monitors at both sites in 2008. The existing transducers are functioning well and will not be replaced. The transducers are still available on the market. It would be advisable to have a few spares at each site.

### 6.6.4 Temperature Monitoring

Temperature monitoring is an integral part of the DCS system whereby critical temperatures are brought into the DCS either as analog inputs from RTDs and thermocouples or as discrete signals from temperature switches. Bearings, windings, glycol, oil, fuel, and air are some of the quantities being measured. Critical temperatures can cause alarming, power limiting or unit shutdown as appropriate.

HYDRO staff reported that the type J and K thermocouple wire and terminal blocks in various junction boxes were replaced during the controls upgrade in 1999. There are sufficient temperature monitoring instrumentation and indications both in the field and at the DCS according to operations and P&C staff. There were no deficiencies observed in the temperature monitoring equipment at the time of the site visit.

Faulty temperature instrumentation has been replaced in the past on an as-needed basis. In 1994 and 2002, thermocouples were replaced on Gas Generators A and B; however, the Station Log does not specify which units or sub-system was at fault. In 2005, an exhaust thermocouple was giving a bad quality signal on Gas Generator B. Again, the Station Log does not specify what action was taken.

Temperature element failures are likely to occur over the next 15 years. One approach which HYDRO could take with regards to thermocouple and RTD maintenance is to replace the elements on each sub-system at the time of a major overhaul. Elements which can be easily changed and have no shutdown initiation can be replaced as they fail. Dual element thermocouples are likely not a cause for concern since the second element is available when the first one fails. Existing spares should be reviewed.

Temperature switches have not shown any failures at Stephenville. Exact replacements will not likely be available over the next 15 years, but it is very easy to source an equivalent switch with a compatible temperature range. Temperature switches are dry contact devices so there is no issue with supply voltage level. Installation detail will not likely be an issue as the switches are normally surface-mounted or mounted with a standard pipe size and thread type. Switch size should not be a problem since instrumentation generally shrinks in size over the years and will therefore fit in the footprint of the device being replaced.

### 6.6.5 Instrument Calibrations

Stantec could not find any evidence that transmitters and switches are being periodically calibrated. Operations could not recall these activities being done. Stantec recommends routine calibrations of all instruments. Initially all instruments should be calibrated and the frequency of recheck should be dependent on the stability of the instrument. Non stable instruments should be replaced.

### 6.6.6 Control Valves

There are several control valves including a temperature regulating valve in the glycol system, a pressure controlled valve in the lube oil system, and control valves in the fuel system. These valves are original equipment with the exception of the motorized valve at the fuel tank. As such, it may be difficult to get spare parts and support, although the station logs have indicated replacing internals in some of these valves. NLH should examine the design conditions for these valves to determine if the conditions can be met today in a package that is a direct replacement. If not, some redesign of piping will be required should a valve have to be replaced. This is best determined in advance so a plan can be generated and sufficient spares stocked. Stantec recommends one spare for each of the original equipment control valves.

Anti-Icing Valve

There have been several incidents of shutdown due to anti-ice valve failure. Stantec recommends at least making the response to an anti-ice valve operation a power limited condition rather than a full shutdown. The logic can likely accommodate this change.

Fuel Tank Motorized Valve

The motorized valve on the fuel tank is new and works well with one exception. There appears to be a deficiency in the logic in which the valve will not open until a certain time delay after an engine has successfully completed its start up sequence. Once the engine has started it is consuming fuel oil while the motorized valve is still closed. Eventually it uses all of the fuel in the line between the engine and the fuel tank, and the unit shuts down. Logic changes appear to be in order to correct this problem.

### 6.6.7 Remote Control and Monitoring

Remote control and monitoring of the Stephenville Gas Turbine at the Energy Control Centre (ECC) in St. John's is accomplished through a SCADA system interface to the DCS. The SCADA system was recently upgraded in 2006. The SCADA system is not part of the Condition Assessment Study scope.

P&C personnel have indicated that future upgrades are being considered. In particular, data transferred from the Gas Turbine sites to ECC could be expanded and stored on a PI historian at ECC. According to P&C personnel, HYDRO has a central group that deals with SCADA maintenance and upgrades.

### 6.6.8 Junction Boxes

Some of the junction boxes mounted on the exterior of the Gas Turbine enclosure (Photos: SVL-034 & 035) have corroded terminal blocks and are partially opened to the weather. The corroded terminal blocks need to be replaced in 2007 or 2008. The junction boxes should be made water tight by installing a weather tight box around each existing box. There is one installation like this already existing on the unit. The new box is surface mounted around the existing one. This would be the cheapest and easiest solution.

Both turbine units still have the original on-engine electrical junction boxes. It is recommended that these boxes be moved off-engine, to isolate the terminations from engine vibration and heat.

### 6.6.9 General Comments

There is no guarantee that any particular instrumentation component will last another 15 years without repair or replacement. However, most of the instrumentation will have suitable replacements.

It would be a beneficial project for HYDRO to create a specification sheet for each piece of instrumentation. Nameplate data, set points, ranges of operation, flange rating, face to face dimensions, etc, could be recorded. Where nameplates and other information are unreadable or unavailable, the exercise of creating the spec sheets will require a bit of research but could be done under non-breakdown conditions.

Having this information available electronically will make sourcing of suitable replacement instruments easier. Identifying replacements could be done in advance to build a spares inventory. The spec sheets could identify several instruments which could use a common spare. Maintenance notes could be added to the spec sheets to track repairs and calibration.

Some of the more complicated retrofits, such as a control valve which requires piping modifications, could be done on a project basis when the valve nears the end of its serviceability.

Stantec is not aware of the program used by HYDRO for the routine calibrations or testing of switches. HYDRO should confirm that the current set points of all instrumentation are in line with manufacturer's original operational design set points. Further, HYDRO should confirm that all instrumentation is functioning properly.

Spares should be stocked for each type of instrumentation device when delivery lead times are long.

## 6.7 BUILDINGS

### 6.7.1 Control Building

The existing control building is a single story prefabricated steel structure supported by cast-in-place concrete foundations and with a concrete slab on grade. The exterior building envelop consists of sheet metal siding and roofing.

Based on the degree of fading and corrosion of the existing cladding and roofing it appears that they are original and therefore were likely installed in 1975 when the gas turbines were installed. The typical design life of this type of material is between 35 and 40 years of age. If this cladding is original, it is nearing its design life.

The cladding is generally quite faded and corrosion is appearing in many places over all the buildings cladding. Typically corrosion of the cladding is evident along the bottoms of the cladding panels, there are many areas where spots of surface corrosion are developing on the exterior of the panel and in many places small pin holes have developed in the coating of the cladding and corrosion is visible in these locations. Corrosion of the sheet metal roof is also evident along the entire perimeter of the building. Based on the condition of the existing cladding and roofing it is likely that these items will have to be replaced within the next five (5) years (Photos: SVL-036 & 037).

There are also several locations where the existing cladding requires immediate repairs to prevent water intrusion into the wall system. The cladding on the corner adjacent to the air tanks on the rear of the control building is damaged and could allow water intrusion. The cladding must be properly sealed around the air piping penetrating the cladding and there are two holes in the rear of the building which are approximately 2” in diameter which should be properly sealed.

The windows in the building are in acceptable condition. However, the exterior wood fascia is in need of painting this year. The interior of the building is generally in acceptable condition and no significant issues were noted. The roof structure was visible in two locations where ceiling tiles had been removed. The roof structure which was visible for inspection was found to be in good condition.

We have noted two areas that are potential safety hazards. The steps up to the platform containing the controls for the gas turbine units are quite large with a rise of 12 ½”. The National Building Code does not permit a step over 7 ½” in height. We therefore recommend that intermediate steps be installed at these locations (Photo: SVL-038). In one location at the south-east corner of the room the step will have to be removable since an electrical trench with

removable covers is located directly below the step (Photo: SVL-039). As well, one of the steel covers for the exterior electrical trench at the rear of the building is not properly supported or fastened down. A person can easily trip over the cover or step through the cover and it presents a safety hazard. We recommend that this particular item be addresses as soon as possible.

### 6.7.2 Fuel Forwarding Building

The existing fuel forwarding building is a single-story prefabricated structure located on the south-west corner of the property. The building is approximately 20' x 28' in plan and 8' high. The exterior of the building consists of sheet metal siding and roofing with sheet metal liner panels on the interior of the building. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade floor approximately 52" below the exterior finished grade. This arrangement provides approximately 12' of head room inside the building. The building is ventilated by a single exhaust fan and supply louvre.

During the site inspection, it was noted that there was a strong diesel odour in the building even with the door open and the exhaust fans running for some time before entering. The likely cause of this odour is the drainage system in the building. Currently, the floor slopes to in-floor channels that then drain to a sump which retains some liquids. The fact that the sump does not completely drain is likely contributing to the fumes and odour inside the building. As well, this sump drains through underground piping to a large concrete sump to the south of the building inside the fuel storage containment dyke. This exterior sump does not have an outlet and simply stores all material collected from the building. HYDRO site personnel indicated that this sump is pumped out roughly on a yearly basis. It is quite likely that fumes from this sump are migrating back into the building through the underground piping. It is unknown if a p-trap has been installed in the underground piping. If a p-trap was installed, it is likely that it is not functioning properly since it can dry out when there are low volumes flowing through the drainage system. Given that there is no water supply in the building, it is very unlikely that a p-trap primer has been installed to prevent dry-out of the p-trap. As well, anything that does collect in the p-trap likely has a high concentration of hydrocarbons and will contribute to the odour in the building.

The existing concrete dyke at the off-loading station is in good condition with no visible cracking. This dyke drains, via underground piping, to the storage sump noted above inside the fuel storage containment dyke. Site personnel indicated that the drain in the concrete dyke is plugged before beginning any off-loading of diesel fuel to help contain any spills. However, it was noted that the bleed valve used to remove air from the system is not located over the containment dyke. Therefore, any diesel fuel which is released through this valve through the bleed process falls to the grade and is not captured by the concrete containment dyke. We therefore recommend that the existing piping be modified so that the bleed valve is located over

the concrete containment dyke thus any diesel fuel escaping from the system can be properly contained (Photo: SVL-040).

It was noted that the area surrounding the concrete off-loading dyke was just gravel. We recommend that this area be paved to help contain and facilitate clean-up of any minor spills that may occur when the off-loading hose of the delivery truck is being hooked up to the oil transfer system (Photo: SVL-041).

It was noted that the existing gutters on the fuel forwarding building are badly corroded with perforations in several areas. These gutters and downspouts require full replacement (Photo: SVL-042). Based on the degree of fading and corrosion of the existing cladding and roofing, it appears that they are original and therefore were likely installed in 1975 when the gas turbines were installed. The typical design life of this type of material is between 35 and 40 years of age. If this cladding is original, it is nearing its design life. The cladding is generally faded and light corrosion is appearing in several places. The west wall of the building is in the worst condition with more advanced corrosion at the corners. We recommend that the cladding on the west wall be replaced in the next year and the remainder of the cladding and roofing will likely have to be replaced within the next five (5) years (Photo: SVL-043).

The steel structure was not visible during our site assessment. However, the interior ceiling and wall liner panels are in good condition and there are no signs of corrosion or water staining. This indicates that there has been limited water leakage and the structure of the building is likely to be in good condition.

As part of this assessment, we also reviewed the condition of the existing slab on grade, concrete foundation wall and concrete equipment plinths. All were found to be in generally good condition with minor shrinkage cracking in the floor slab and foundation walls.

At the July 17, 2007 Kick-off Meeting, Stantec was asked to consider whether the building should be classified as a hazardous location due to the diesel oil odours and the fact the interior floor is approximately 52” below the exterior finished grade.

A Class 1 hazardous location is one in which flammable gases or vapours are or may be present in the air in quantities sufficient to produce explosive gas atmospheres. Class 1 locations may be further divided into three Zones based on the frequency of occurrence and duration of an explosive gas or atmosphere. Zone 0 is a location in which explosive gas atmospheres are present continuously or are present for long periods; Zone 1 is a location in which explosive gas atmospheres are likely to occur in normal operation; Zone 2 is a location in which explosive gas atmospheres are not likely to occur in normal operation and if they do occur they will exist for a short time only.

API Recommended Practice 505, Section 5.2.1 identifies Class III liquids as having a flash point above 60C (140F). Diesel Oil and Fuel Oil #2 have flash points of about 77C (170F) ie they are

Class III liquids. Article 5.2.4.1 says: “Class III liquids normally do not produce vapours of sufficient quantity to be considered for electrical classification purposes. Class III liquids will release vapour in the flammable range at their surfaces if heated above their flash points, but the extent of the classified location ordinarily will be very small and near the point of release”.

With a well applied maintenance program, the possibilities of leaks from pipe joints and valve heads are low. Also considering the vapour from the diesel fuel is heavier than air, we could expect any vapour will be settled towards the floor. The diesel fuel is a “combustible liquid”, not a “flammable liquid”. Our interpretation is that with adequate ventilation, the fuel forwarding building could be considered as a non-classified area and the electrical equipment and wiring does not have to comply with the requirement for a Zone 1 or Zone 2 area usually applied to a hydrocarbon pumping station.

We recommend that HYDRO review the buildings ventilation system and possibly install additional air intake louvers and ducting to convey incoming air to foundation level and provide adequate ventilation to the building (API RP505 outlines a number of methods for demonstrating or meeting the requirement for “adequate ventilation”). The proposed inlet air system should be at the diametrically opposite wall from the existing ventilation fan. HYDRO should also consider the need for a larger or additional exhaust fan. As well the sump in the building should be cleaned on a more frequent basis.

### 6.7.3 Parts Storage Shed

The parts storage shed located in the north-west corner of the facility was also reviewed as part of this assessment. The storage shed is constructed of timber framed walls and roof on a concrete slab on grade. The building envelop consists of an asphalt shingled roof and vinyl siding.

The existing asphalt shingles have been installed over old shingles and are in acceptable condition. However, the shingles are weathered and will likely require replacement within the next five (5) to seven (7) years (Photo: SVL-044). The vinyl siding is in acceptable condition.

The existing overhead door is showing signs of rot and is in poor condition. We recommend replacement of the door with a new commercial grade overhead door complete with proper weather stripping. The existing entry door and frame are also in poor condition. There are large gaps along the bottom of the door which can allow rodents, snow and water to enter. The door is also quite difficult to operate. We recommend that the existing man door and frame be replaced with a new commercial grade door and frame with proper weather stripping and commercial grade hardware (Photo: SVL-045 7 046). The existing windows in the west and east sides of the building are in acceptable condition, but painting of the exterior wood fascia is required.

The interior drywall and plywood sheathing is in generally good condition with only one crack in the drywall which is located over the electrical panel on the south-east corner of the building. The concrete slab on grade was also reviewed and was found to be in good condition. The timber framing for this structure was not visible or accessible so we cannot comment on the condition of this item.

It was noted that the existing brackets to support the ladder were damaged and were quite high. We recommend that these brackets be replaced with new ones installed lower on the wall to make storing the ladder easier and safer. HYDRO site personnel also indicated that rodents were entering the storage shed and chewing up the filters stored in this building. Installation of a new man door and overhead door will minimize the number of places for rodents to enter. However, overhead doors are difficult to seal completely and consideration should be given to installing rodent proof metal cabinets for storage of the filters (Photo: SVL-047).

### 6.7.4 Waste Oil Storage Shed

The existing waste oil storage shed (Photo: SVL-049) located just east of the control building is an old transportation container converted to a shed. The shed has a steel exterior with timber framing on the interior. A timber-framed roof with asphalt shingles has been added to the container. The roofing and door of this shed are in very poor condition and are in need of replacement (Photo: SVL-048). The shed is not equipped with any ventilation, fire detection or suppression systems.

Given the timber construction of the shed, the waste oil stored in the shed, the high temperatures noted during warm weather and lack of fire alarm or sprinkler system, we recommend that the waste oil storage shed be relocated a minimum of 100 feet from the existing control building for safety purposes. Given that waste oil is stored in this structure, it is advisable to relocate the waste oil storage shed inside the oil storage containment dyke to contain any spills that may occur. Based on the condition of the existing shed, we recommend that this structure be replaced with a new non-combustible structure such as a new steel transportation container.

### 6.7.5 Emergency Back-up Diesel Generator Building

The existing diesel generator building is a single-story structure that is approximate 150 square feet in size. The exterior of the building consists of vertical sheet metal siding and asphalt shingle roofing. The building is supported by cast-in-place concrete foundations and has a concrete slab on grade. For oil containment, the building has a 150 mm high containment wall that extends up from the floor slab around the perimeter of the building. The wall is approximately 65 mm high near the door. The interior of the building is finished with painted plywood.

The building was built in 2005. The exterior cladding, roofing and doors on the building were found to be in good condition and no deterioration or corrosion was noted. The concrete slab

on grade and interior plywood finishes were also found to be in good condition. An exhaust fan and louvre have also been installed to provide ventilation for the building.

### 6.7.6 General Comments

Only visual inspections were carried out as part of this assessment. Not all structural components were visible or accessible at the time of inspection. No non-destructive or destructive testing was carried out on any of the structures noted above as part of the inspection. Therefore this assessment should not be considered an exhaustive inspection of all civil/structural components. As well, it is important to note that no detailed analysis was completed as part of this assessment to determine the adequacy of different structures for their purpose.

## 6.8 ENVIRONMENTAL

The Condition Assessment Study addressed several environmental issues as they relate to the Stephenville site, specifically soils contamination and air emissions.

**Soil Contamination**

A review of several environmental reports provided by HYDRO indicates there have been a number of spills and leaks of petroleum products at the Stephenville site over the past 30 years. The petroleum products include #2 diesel fuel, lubricating oils and transformer oils. These spills and leaks resulted in soil contamination at various locations including the diesel fuel bulk storage tank area and the gas turbine / terminal station area. The following are a few examples of recorded spills and leaks:

- In 1991 an oil/water separator overflowed and impacted surrounding soils.
- In 1992 a diesel fuel spill of approximately 18,630 Litres due to mechanical failure.
- In 2000 during diesel fuel bulk storage tank upgrading there was remediation of contaminated soil in the vicinity of the leveling valve at Tank 1. Remediation was also conducted in the offloading area during the storage tank upgrading.

In all cases, these spills and leaks were cleaned to the satisfaction of the Department of Environment and confirmatory sampling revealed no unacceptable levels of impacts in the remaining soil.

Since 2001, HYDRO has initiated a number of environmental studies to investigate these impacts. These studies include:

- Jacques Whitford Phase I Environmental Site Assessment in 2002
- Jacques Whitford Phase II Environmental Site Assessment and Health and Screening Level Ecological Risk Assessment in 2006

The Jacques Whitford 2006 Study concluded that under existing conditions and for the identified concentrations of Chemicals or Contaminant of Concern (COC) found at the site, the potential

for unacceptable risks to human health and ecological health is not likely. While petroleum hydrocarbons were detected in a number of soil samples and in several monitoring wells, their concentrations were well below unacceptable levels. The Jacques Whitford 2006 Study also tested for numerous other soil and water contaminants and while concentrations of a number of contaminants were detected their concentrations, with the exception of zinc, were well below unacceptable levels.

The Stephenville site, as of 2006, had an excellent soils environmental record.

Air Emissions

The gas turbine produces air emissions related to the combustion of diesel oil. The exhaust emissions are not filtered or treated. There is no Continuous Emissions Monitor System (CEMS) on either exhaust stack. The various HYDRO inspection check lists included in Appendix 5, do not list exhaust stack emission manual sampling as an activity. Data on stack(s) emissions testing that may have been conducted by HYDRO in the past was not available for review.

Exhaust emissions from the gas turbine fall under Newfoundland and Labrador Regulation 39/04, Air Pollution and Control Regulations (O.C. 2004-232). The Regulations list limits on the concentration of air contaminants due to all emitting sources. The concentrations are defined by periods of time during which the concentrations exist. It would appear that the present operational mode of the gas turbine, as predominately synchronous condenser operation, would be within the criteria listed in the Regulations. If the predominant operational mode in the future is generation on a somewhat continuous basis, HYDRO should be aware of the potential application of the air contaminant limits in the Regulations.

The Regulations state that an owner or operator who installs a new or modified emission source shall employ the best available control technology with respect to air emissions. This requirement however does not apply to parts replacement but would likely apply to the installation of a new gas turbine.

The Study did not take an exhaustive look at air emission issues at the Stephenville site. The issue of air emissions is noted in this Report for the express purpose of making the reader aware that any future significant generation operational mode change or significant work carried out at the site, as a follow-up to this Report, depending on the nature of that work, could involve the application of the criteria in the Regulations.

# 7.0 GAS TURBINE FACILITY 15 YEAR LIFE EXTENSION OPTIONS

## 7.1 GENERAL

The primary focus of the Study involved a condition assessment of existing Gas Turbine Facility equipment in order to determine which components may require refurbishment, repair or replacement due to equipment ageing effects, obsolescence or maintenance practices in order to provide reliable operation over the next 15 years. The HYDRO Request for Proposal (RFP) included the following work scope:

- Assess both sites for potential problems in continuing to operate the Facilities as they presently exist for the next 15 years. The Study will recommend solutions with associated cost estimates for maintaining and running the Facilities as reliable generating units.

In addition, the RFP required that the Study evaluate two other options for redeveloping the sites as follows:

- Option 1 - Replace the major equipment items and systems with new at one site. Existing infrastructures would be utilized where considered to be suitable for continued long term use. The components removed would be used as spares for the other site.

- Option 2 - Replace major equipment items and systems with new at both sites. Existing infrastructures would be utilized where considered to be suitable for continued long term use.

In order to address these requirements, the Study identified and provided cost estimates for the following base cases and options:

Base Case:

- Base Case 1 - Refurbishment of the existing Gas Turbine Facilities at Hardwoods

- Base Case 2 - Refurbishment of the existing Gas Turbine Facilities at Stephenville

Replacement Options at one or both sites:

- Option 1 – New Gas Generators (Engines) & Power Turbines
- Option 2 – New Alternator / Exciter
- Option 3 - New Gas Turbine
- Option 4 - New Dynamic VAR Compensator

Temporary Gas Turbine Rental

- To provide backup for MWs or MVARs while refurbishment or replacement work is underway at a site

This section of the Report will provide an overview of the technical aspects of the Base Cases and the Options as well as the costs associated with each. **The costs are summarized in Appendix 6.** Costs are considered to have an accuracy of (+/-) 30% and serve as a comparison of the relative costs of each Option to the Base Cases in the life cycle cost analysis that follows in Section 8.0. If HYDRO decides to proceed with either the Base Case or any of the Options, a more in-depth detailed capital cost estimate should be developed.

## 7.2 BASE CASE – REFURBISHMENT OF EXISTING GAS TURBINE FACILITIES

### 7.2.1 Hardwoods Gas Turbine Facility Refurbishment Recommendations

Report Section 5.0 provided a condition assessment of the existing equipment and structures at the Hardwoods Gas Turbine site. The various refurbishment recommendations contained in Section 5.0 along with associated costs are summarized in a spreadsheet included in Appendix 6. The following is a summary of the costs on an equipment or structure basis.

**Table 1**
**Hardwoods GT Facility Refurbishment Costs**
**(2007 Costs)**

| Item | Equipment / Structure | Cost (Cdn$) |
|---|---|---|
| | | |
| 1 | Gas Generator Engines / Power Turbines Equipment | $1,263,720.00 |
| 2 | Inlet Air Systems A & B | 62,300.00 |
| 3 | Exhaust Stacks A & B | 95,000.00 |
| 4 | Glycol Cooler for Main Lube Oil | 9,500.00 |
| 5 | Gas Generator / Power Turbine Enclosures A & B | 22,600.00 |
| 6 | Alternator and Excitation System | 2,122,000.00 |
| 7 | Alternator Enclosure | 10,600.00 |
| 8 | Fuel Oil System | 45,250.00 |
| 9 | Electrical Systems | 123,100.00 |
| 10 | Control & Instrumentation Systems | 70,100.00 |
| 11 | Buildings | 44,700.00 |
| 13 | Miscellaneous HYDRO Work on Ongoing Operational Issues (labour & materials) | 250,000.00 |
| | **Sub-Total:** | $4,118,870.00 |
| | HYDRO labour & overhead costs relative to Items 1 – 13 (assume 8% of sub-total) | 329,510.00 |
| 14 | Spare Parts (common to both Sites) | 58,500.00 |
| | | |
| | **Total:** | **$4,506,880.00** |

Commentary follows on each category of costs:

1. Gas Generator Engines / Power Turbines Equipment

   Refurbishment costs for this category were provided by Robin Sipe of S&S Turbines Services Limited. Mr. Sipe has extensive experience servicing Olympus C engines. The engines would be removed and reinstalled by S&S Turbine's personnel and shipped to Fort St. John BC for refurbishment. Approximately 90 days turn around time would be required to refurbish and test run an engine at the Fort St. John facility. S&S Turbines can provide, at HYDRO's discretion, an engine on a temporary basis to replace an engine shipped to Fort St. John. With a rental engine on site, the engines would be shipped piecemeal such that each site always has 2 engines in service. The costs include replacing the ignition exciters, the speed governors and fuel valve assemblies. It should be noted that previous refurbishment work on a single engine in 2000 by another service provider was at a substantially higher cost approaching $1.1 million.

   The power turbines will be thoroughly inspected, when an engine has been removed, and refurbished as required. The cost estimate for the power turbine refurbishment anticipates minimal refurbishment work based on observations during the site visits. The condition of the power turbines will be better known when removed from the enclosures. There could however be additional costs involved following a thorough examination of the power turbines, following the removal of the gas generator engines. There is also a cost included to dismantle and inspect the power turbine clutches.

2. Inlet Air Systems A & B

   These costs include a number of miscellaneous civil refurbishments to the inlet air systems on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

3. Exhaust Stacks A & B

   These costs include a number of miscellaneous civil refurbishments to the exhaust stacks on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

4. Glycol Cooler for Main Lube Oil

   The costs cover the refurbishment of the existing glycol cooler. Refer to Appendix 6 for details. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

5. Gas Generator/Power Turbine Enclosures A & B

   The costs cover the removal of corrosion and re-coating the enclosures A & B where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

6. Alternator and Excitation System

   As discussed in sub-section 5.3.3, due to the absence of electrical testing and visual inspection records on the Alternator over its 30 years of service, it is not possible to determine the present condition of the alternator and exciter and make an assessment of its life expectancy and reliability over the next 15 years. In order to determine the present condition of the alternator and exciter, certain basic electrical tests and visual inspections are necessary. Therefore, the costs in this category include: (i) conducting electrical tests on the stator, rotor and exciter with the alternator in its enclosure (ii) removing the alternator or as a minimum the rotor from its enclosure and carrying out visual inspections and other electrical tests on the stator and the rotor (removed from the stator). The cost estimate assumes major refurbishment work on the alternator and the carrying out the necessary refurbishment work at a supplier's shop. The estimate should be considered a worst case upper end cost for alternator refurbishments. Input to the refurbishment estimate was provided by MAN TURBO.

7. Alternator Enclosure

   The costs cover the removal of corrosion and re-coating of the enclosures where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

8. Fuel Oil System

   These costs include a number of miscellaneous civil refurbishments to the oil storage tank. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

9. Electrical Systems

The Hardwoods electrical equipment was generally in good condition and should perform reliably over the next 15 years. Appendix 6 lists a number of refurbishment recommendations and associated costs for HYDRO's consideration. Pricing of the listed equipment was sourced from equipment suppliers. Costs associated with the recommended cabling modifications are at best a ballpark estimate as the detailed work to identify the number of affected power cables, their lengths and routing was not included in the scope of this Study. A more detailed evaluation of the extent and costs associated with replacing and installing the power cables in a separate compartment (item 38) is best left to HYDRO.

10. Control & Instrumentation Systems

The ELSAG Bailey INFI 90 DCS system installed in 1997 appears to be working relatively well. While there are currently shortcomings in the existing software/hardware, the storage of data and trending capability, the equipment modifications proposed by HYDRO as outlined in sub-section 5.6.1 should address current problems and improve system capacity and reliability for a further 15 years. In addition, the supplier of this equipment will support the equipment for years to come. Refer to Appendix 6 for further details on other proposed recommendations and costs.

11. Buildings

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Unloading Building (iii) Fuel Forwarding Building (iv) Auxiliary Module Building (v) Maintenance and Parts Storage Building and (vi) High Voltage Switchgear Building. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

12. HYDRO Labour and Overhead Costs Relative to Above Items

It is recommended that HYDRO establish a refurbishment project team to organize, award and oversee the work on the Hardwoods items 1 through 11. A preliminary budget cost of 8% of the total capital dollars for these items has been allowed for the labour and expenses of the project team.

13. Miscellaneous Work on Ongoing Operational Issues

Section 4.0 of this Report provided commentary on ongoing operational issues and routine maintenance work carried out at each site over the past 8 years. The Study schedule, budget and scope did not allow the investigation of these sporadic

operational issues. It is recommended that HYDRO allocate, as part of the overall refurbishment work budget at each site, an amount of money to thoroughly investigate, engineer and implement solutions to these ongoing sporadic operational issues. It is proposed that a figure of $250,000.00 be allowed for this purpose as part of an overall refurbishment budget.

14. Spare Parts

The spare parts list in Appendix 6 is not comprehensive by any means. A comprehensive review of existing spare parts at the sites was not conducted in the Study. The spare parts list, provided by HYDRO, of currently held spares at the sites was dated 2004 and likely not current. In addition to the spares listed in Appendix 6, it is recommended that HYDRO stock spare cards for each type of card in the DCS System as well as other long term delivery equipment items where a failure of the item could seriously jeopardize the reliability and availability of the Gas Turbine.

### 7.2.2 Stephenville Gas Turbine Facility Refurbishment Recommendations

Report Section 6.0 provided a condition assessment of the existing equipment and structures at the Stephenville Gas Turbine site. The various refurbishment recommendations contained in Section 6.0 along with associated costs are summarized in a spreadsheet included in Appendix 6. The following is a summary of the costs on an equipment or structure basis.

**Table 2**
**Stephenville GT Facility Refurbishment Costs**
**(2007 Costs)**

| Item | Equipment / Structure | Cost (Cdn$) |
|---|---|---|
| | | |
| 1 | Gas Generator Engines / Power Turbines Equipment | $1,142,520.00 |
| 2 | Inlet Air Systems A & B | 34,700.00 |
| 3 | Exhaust Stacks A & B | 36,900.00 |
| 4 | Glycol Cooler for Main Lube Oil | 10,000.00 |
| 5 | Gas Generator / Power Turbine Enclosures A & B | 18,300.00 |
| 6 | Fire Detection and Protection | 45,000.00 |
| 7 | Alternator and Excitation System | 2,347,000.00 |
| 8 | Alternator Enclosure | 3,600.00 |
| 9 | Alternator Air Cooling System Glycol Cooler | 21,900.00 |
| 10 | Fuel Oil System | 19,750.00 |
| 11 | Electrical Systems | 129,600.00 |
| 12 | Control & Instrumentation Systems | 69,000.00 |
| 13 | Buildings | 74,400.00 |
| 15 | Miscellaneous HYDRO Work on Ongoing Operational Issues | 250,000.00 |
| | **Sub-Total**: | $4,202,670.00 |
| | HYDRO labour & overhead costs relative to Items 1 – 15 (assume 8% of sub-total) | 336,213.00 |
| | | |
| | **Total:** | **$4,538,883.00** |

Commentary follows on each category of costs:

1. Gas Generator Engines / Power Turbines Equipment

   Refurbishment costs for this category were provided by Robin Sipe of S&S Turbines Services Limited. Mr. Sipe has extensive experience servicing Olympus C engines. The engines would be removed and reinstalled by S&S Turbine's personnel and shipped to Fort St. John BC for refurbishment. Approximately 90 days turn around time would be required to refurbish and test run an engine at the Fort St. John facility. S&S Turbines can provide, at HYDRO's discretion, an engine on a temporary basis to replace the engine shipped to Fort St. John. With a rental engine on site, the engines would be shipped piecemeal such that each site always has 2 engines in service. The costs also include replacing the ignition exciters, the speed governors and fuel valve assemblies. It should be noted that previous refurbishment work on a single engine in 2000 by another service provider was at a substantially higher cost approaching $1.1 million.

   The power turbines will be thoroughly inspected, when an engine has been removed, and refurbished as required. The cost estimate for the power turbine refurbishment anticipates minimal refurbishment work based on observations during the site visits.

The condition of the power turbines will be better known when removed from the enclosures. There could however be additional costs involved following a thorough examination of the power turbines, following the removal of the gas generator engines. There is also a cost included to dismantle and inspect the power turbine clutches.

2. Inlet Air Systems A & B

   These costs include a number of miscellaneous civil refurbishments to the inlet air systems on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

3. Exhaust Stacks A & B

   These costs include a number of miscellaneous civil refurbishments to the exhaust stacks on each end of the Gas Turbines. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

4. Glycol Cooler for Main Lube Oil

   The costs cover the refurbishment of the existing glycol cooler including replacement of the bottom section, canopy cladding plus re-coating the entire structure as well as cleaning the tubes in the heat exchanger. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

5. Gas Generator / Power Turbine Enclosures A & B

   The costs cover the removal of corrosion and re-coating the enclosures A & B where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

6. Fire Detection and Protection

   The costs include the supply and installation of an Inergen fire suppression system in the Control Building. Prices were obtained from an Inergen supplier.

7. Alternator and Excitation System

   As discussed in sub-section 6.3.3, due to the absence of electrical testing and visual inspection records on the Alternator over its 30 years of service, it is not possible to

determine the present condition of the alternator and exciter and make an assessment of its life expectancy and reliability over the next 15 years. In order to determine the present condition of the alternator and exciter, certain basic electrical tests and visual inspections are necessary. Therefore, the costs in this category include: (i) conducting electrical tests on the stator, rotor and exciter with the alternator in its enclosure (ii) removing the alternator or as a minimum the rotor from its enclosure and carrying out visual inspections and other electrical tests on the stator and the rotor (removed from the stator). The cost estimate assumes major refurbishment work on the alternator and carrying out the necessary refurbishment work at a supplier's shop. The estimate should be considered a worst case upper end cost. Input to the refurbishment estimate was provided by MAN TURBO.

8. Alternator Enclosure

   The costs cover the removal of corrosion and re-coating the enclosures where required. Also included are modifications to the man doors on each enclosure. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

9. Alternator Air Cooling System Glycol Cooler

   The costs cover the refurbishment of the existing glycol cooler including replacement of the canopy cladding plus re-coating the entire structure including the support structure, sealing of joints as well as cleaning the tubes in the heat exchanger. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

10. Fuel Oil System

    These costs include a number of miscellaneous civil refurbishments to the oil storage tank as well as modifications to the containment dyke. Refer to Appendix 6 for details. The recommended refurbishments are for structural integrity and safety reasons. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

11. Electrical Systems

    The Stephenville electrical equipment was generally in good condition and should perform reliably over the next 15 years. Appendix 6 lists a number of refurbishment recommendations and associated costs for HYDRO's consideration. Pricing of the listed equipment was sourced from equipment suppliers.

12. Control and Instrumentation Systems

The ELSAG Bailey INFI 90 DCS system installed in 1999 appears to be working relatively well. While there are currently shortcomings in the existing software/hardware, the storage of data and trending capability, the equipment modifications proposed by HYDRO as outlined in sub-section 6.6.1 should address current problems and improve system capacity and reliability for a further 15 years. In addition, the supplier of this equipment will support the equipment for years to come. Refer to Appendix 6 for further details on other proposed recommendations and costs.

13. Buildings

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Forwarding Building (iii) Parts Storage Building and (iv) Waste Oil Storage Shed. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

This category of costs addresses recommendations for refurbishment work on various buildings on the site. Buildings include: (i) Control Building (ii) Fuel Unloading Building (iii) Fuel Forwarding Building (iv) Auxiliary Module Building (v) Maintenance and Parts Storage Building and (vi) High Voltage Switchgear Building. The refurbishments include roofing, cladding and other maintenance work on the Buildings to ensure their structural integrity for a further 15 years. The civil cost estimates were derived from the RS Means 2007 Cost Estimating Data Books adjusted to reflect the construction scene in Newfoundland and Labrador.

14. HYDRO Labour & Overhead Costs Relative to Above Items

It is recommended that HYDRO establish a refurbishment project team to organize, award and oversee the work on the Stephenville items 1 through 13. A preliminary budget cost of 8% of the total capital dollars for these items has been allowed for the labour and expenses of the project team.

15. Miscellaneous Work on Ongoing Operational Issues

Section 4.0 of this Report provided commentary on ongoing operational issues and routine maintenance work carried out at each site over the past 8 years. The Study schedule, budget and scope did not allow for the investigation of these sporadic operational issues. It is recommended that HYDRO allocate, as part of the overall refurbishment work budget at each site, an amount of money to thoroughly investigate, engineer and implement solutions to these ongoing sporadic operational

issues. It is proposed that a figure of $250,000.00 be allowed for this purpose as part of an overall refurbishment budget.

## 7.3 OPTIONS – REPLACEMENT OF MAJOR COMPONENTS

The major components considered for replacement included the engine, power turbines and alternator. The costs for these replacements are summarized in a spreadsheet included in Appendix 6.

### 7.3.1 Option 1 – New Gas Generator Engines and Power Turbines

Several equipment suppliers were contacted regarding the replacement of the gas generators and power turbines. MAN TURBO of Europe was the only supplier to provide a qualified cost. MAN TURBO offered two (2) FT8-36 gas turbine engines and power turbines. Each engine/ power turbine is rated at 25 MW. The FT8 aero-derivative machines are Pratt & Whitney machines provided through a cooperation agreement between Pratt & Whitney and MAN TURBO. A copy of the MAN TURBO proposal is included in Appendix 7.

The FT8 engines and power turbines will be supplied complete with auxiliary systems such as lube oil, dryer, fire and CO2 protection, control panel, MCC, etc. It may be possible to utilize existing auxiliary systems however this can only be determined following a detailed review of the existing systems by MAN TURBO. More importantly, excluded from the price provided by MAN TURBO was the air inlet filter assemblies, exhaust stacks, acoustic enclosures or modifications to existing enclosures. It is intended that these structures be reused however any required modifications (and associated costs) to these existing structures would require a detailed review by MAN TURBO. Also excluded from MAN TURBO's scope was any work associated with the existing alternator and SSS clutches, all of which would be re-used following refurbishment (by others) with the new engines and power turbines.

The costs provided by MAN TURBO, converted to present day 2007 Canadian dollars, are as shown in Table 3:

**Table 3**
**Replace Engines and Power Turbines – One Site**
**MAN TURBO Proposal**
**(2007 Costs)**

| Item | Description | Cost (Cdn$) |
|---|---|---|
| | | |
| 1 | USA Portion of Equipment Supply | $14,100,000.00 |
| 2 | European Portion of Equipment Supply | 6,800,000.00 |
| 3 | Transportation to Site (Estimate) | 200,000.00 |
| 4 | Erection and Commissioning | 2,000,000.00 |
| 5 | Other refurbishments - average of Table 1 (Hardwoods) and Table 2 (Stephenville) | 3,319,761.00 |
| | **Sub-Total:** | **$26,419,761.00** |
| 6 | Modifications to existing engine & power Turbine enclosures and exhaust stacks as required | *To be advised pending further study by supplier* |
| | **Total:** | **$** |

The costs do not include modifications to the existing air inlet filter assemblies, exhaust stacks and existing enclosures. Further, there potentially could be some cost savings in utilizing some of the existing balance of plant equipment such as lube oil, MCCs etc. Weighed against this would be liability issues if there should be an engine problem arising from the faulty or non-operation of existing balance of plant equipment

The costs in Table 3 apply to one Gas Turbine site only. The figures would double for both sites. Retrofitting the new engines and power turbines at one site would free up the replaced equipment for use at the second site.

In this option, the existing alternator would be retained and refurbished as required. In addition to the costs for new engines and power turbines at either site, all other refurbishment costs (with the exception of the engines/power turbine refurbishment costs) listed in Table 1 (Hardwoods) and Table 2 (Stephenville) would apply to this option. These additional refurbishment costs would be $3,243,160.00 for Hardwoods and $3,396,363.00 for Stephenville. For the purpose of Table 3, an average of the cost at both sites - $3,319,761.00 - is included.

### 7.3.2 Option 2 – New Alternator/Exciter

It is important to note that the alternators at the Hardwoods and Stephenville sites, while of similar electrical capacity, are different physically. The Stephenville alternator rotor length is 1.64 meters longer than the rotor length at Hardwoods. This difference in length reflects the different cooling systems on each alternator. The Stephenville alternator uses a glycol-water mixture to absorb heat from the air circulating inside the alternator casing and to discharge the

heat to ambient air by means of an external heat exchanger complete with fan cooling. The Hardwoods alternator cooling does not use an external heat exchanger. The Hardwoods cooling system consists of intake filters and discharge louvers located on the alternator enclosure.

Brush Electrical Machines Ltd. in Loughborough, England, the supplier of the original alternator/ exciter, was contacted to provide a price for a new replacement alternator/exciter for one of the sites. Brush has pointed out that their alternator design today is different than it was 30 years ago. Modifications to the existing alternator enclosure and bearings arrangement would likely be required in order to retrofit a new alternator.

Brush provided preliminary ballpark information on the costs of a new generator as summarized in Table 4 below. Brush pointed out that the budget estimates are strictly for guidance and do not cover special features that may be required for the project. The estimates do not include line or neutral cubicles or off generator support systems – external radiators, oil services, clutches, etc. Brush notes that there would need to be careful consideration of the major interfaces to make their current machine fit. The big unknown in the preliminary estimate provided by Brush is the cost associated with these interfaces, modifications to the existing enclosure, bearings, etc. Brush is not prepared to invest at this time, the effort required to define the overall scope and costs of retrofitting a new alternator at either site. These costs could be significant and are not known at this time. For the purposes of Table 4, we have provided a rough estimate of $1,000,000 for the modifications required to incorporate a new alternator into the existing infrastructure. The final estimate will have to be provided by Brush following a more detailed study of the existing infrastructure. Refer to Appendix 8 for details on the Brush proposal.

**Table 4**
**New Alternator / Exciter – One Site**
**(2007 Costs)**

| Item | Description | Cost (Cdn$) |
|---|---|---|
| | | |
| 1 | New alternator / exciter | $2,500,000.00 |
| 2 | Top Mounted standard air filter house | 300,000.00 |
| 3 | Acoustic & weather Protection Canopy | 250,000.00 |
| 4 | Erection & Commissioning (estimate) | 750,000.00 |
| 5 | Transportation (estimate) | 75,000.00 |
| 6 | Interface costs to existing infrastructure & auxiliary systems (estimate) | 1,000,000.00 |
| 7 | Other refurbishments - average of Table 1 (Hardwoods) and Table 2 (Stephenville) | 2,288,381.00 |
| | **Total:** | **$7,163,381.00** |
| | | |

In this option, the existing engines and power turbines would be retained and refurbished. In addition to the costs for a new alternator/exciter at either site, all other refurbishment costs (with the exception of the alternator refurbishment costs) listed in Table 1 (Hardwoods) and Table 2 (Stephenville) would apply to this option. These additional refurbishment costs would be $2,384,880.00 for Hardwoods and $2,191,883.00 for Stephenville. For the purpose of Table 4, an average of the cost at both sites - $2,288,381.00 - is included.

## 7.4 OPTION 3 – NEW GAS TURBINE

Primarily for cost comparison purposes with the other options considered, several equipment suppliers including Siemens, Alstom and General Electric were contacted regarding the supply of a new 50 MW gas turbine for one or both sites. In spite of repeated requests for costing information, the suppliers were unresponsive to our requests. A new gas turbine would replace the Hardwoods or Stephenville Gas Turbines in their entirety, with the exception of the Fuel unloading/storage infrastructure and step-up transformer/grid interconnection infrastructure at each site. A new gas turbine would include:

- Single aero-derivative engine (similar to General Electric LM6000 Gas Turbine)
- Clutch
- 50 MW alternator c/w synchronous condenser capability
- Mechanical Auxiliary Equipment
  - Fuel Forwarding Module
  - Air Compressor Module
  - Lube Oil System
- Electrical Auxiliary Equipment
  - 13.8 kV Switchgear
  - Motor Control Centre; Battery & Charger; Digital Protection Relays; Bus Duct; Motors; Cabling; etc.
  - Station Service Transformer
- Control & Instrumentation Auxiliary Equipment
  - DCS Control System
  - Vibration Monitoring System
  - Temperature Monitoring System
  - New Instrumentation Devices
- Civil Works
  - Site Preparation
  - Foundations

Based on previous work carried out by Stantec for other clients, we would estimate the cost of a new 50 MW Gas Turbine (similar to the General Electric LM 6000 Gas Turbine) installed at either site to be approximately $30 to $35 million. The existing buildings at Stephenville for example would have to be reviewed to determine their suitability in housing the new

mechanical, electrical and controls auxiliary equipment which would be supplied as part of the standard gas turbine package. At Hardwoods, it would be advisable to build a new all purpose building adjacent to the new gas turbine to house all auxiliary equipment.

**Table 5**
**New Gas Turbine – One Site**
**(2007 Costs)**

| Item | Description | Cost (Cdn$) |
|---|---|---|
| | | |
| 1 | New Gas Turbine – Includes supply, erection and commissioning | $35,000,000.00 |
| 2 | Allowance for HYDRO engineering staff involvement in new gas turbine procurement and installation. (estimate) | 400,000.00 |
| | **Sub-Total**: | **$35,400,000.00** |
| 3 | Dismantling of existing Gas Turbine and demolition of buildings as required | 1,500,000.00 |
| | | |
| | **Total:** | **$36,900,000.00** |

The new gas turbine would require a new physical location within the fenced area at either site. The new gas turbine could be installed to a large degree independently of the operation of the existing gas turbine. Following the installation of the new gas turbine, the existing Gas Turbine could be disassembled with the components used as spare parts for the other site. There would be costs involved to dismantle the existing Gas Turbine and remove equipment from the existing buildings. For the purposes of Table 5, we have provided a rough estimate of $1,500,000 for dismantling of the existing Gas Turbine and demolition of surplus buildings and structures.

The installation of a new gas turbine on either site, while the most costly of all options, would have an operational timeframe well beyond 15 years. The installation of a new gas turbine at the Hardwoods site could proceed to the point where connection to the grid and switchover of the fuel supply is required. This would allow the existing Gas Turbine to remain in service for a considerable period while the new gas turbine is being installed.

## 7.5 TEMPORARY MOBILE GAS TURBINE RENTAL

If the alternator at either Hardwoods or Stephenville requires major refurbishment work at a vendor's shop it could be out of service for a period of 3 to 4 months. If the electrical system cannot tolerate an outage of this duration at either site, the option of using a rental mobile gas turbine(s) was explored. From information provided by HYDRO, the existing machines operate predominantly as synchronous condensers with MVAR loadings typically in the range of 10 to

20 MVAR with peaks up to 25 MVAR. A rental mobile gas turbine rated at approximately 25 MW was sourced. Pratt and Whitney and Caterpillar were contacted on this matter.

Pratt and Whitney

Pratt & Whitney has a mobile 25 MW 13.8 kV gas turbine ("MobilePac") that could be available as a rental from a third party. Refer to Appendix 9 for information on the Pratt & Whitney MobilePac gas turbine. Pratt & Whitney currently does not have MobilePac units available for rent directly however they are contemplating getting into the leasing/rental business within the next 2 years. Pratt & Whitney has a number of customers who own MobilePac units and have offered to speak to these customers for the rental of one of their units. In particular, Pratt & Whitney has a European customer with 7 MobilePac units that may be available for lease in the summer months. The European customer requires the units for winter peak loads. Pratt & Whitney stated that HYDRO should contact them (Phil Vecchiarelli at 860-565-7877) if there is an interest in pursuing such a rental arrangement. Pratt & Whitney submitted the following preliminary cost estimate ($USA) based on a 4 month rental arrangement. Costs would be firmed up if HYDRO has an interest in the MobilePac gas turbine.

**Table 6A**
**P&W MobilePac Gas Turbine**
**2007 Preliminary Rental Costs (USA$)**

| Description | Unit Cost | Total Cost (4 Months) |
|---|---|---|
| P & W 25MW GT – 4 Month Rental | | |
| o Transportation to Site | | $ 625,000.00 |
| o Site Set up Fee (per site) | | 150,000.00 |
| o HV Connection | | 50,000.00 |
| o Fuel Connection | | 7,500.00 |
| o Monthly rental – 4 months | $400,000.00 | 1,600,000.00 |
| o Full Time Site Supervisor – 4 months | 25,000.00 | 100,000.00 |
| o Site Dismantle Fee (per site) | | 150,000.00 |
| o Transportation back to Europe | | 625,000.00 |
| | | |
| **Total:** | | **$3,307,500.00** |

These costs while in USA$ are equivalent to Cdn$ at the present time. Since Pratt & Whitney are involving a European customer in this potential transaction, Euros$ will likely play a role in any final rental arrangement. The costs in Table 6A apply to one site. If the work at both sites can be accommodated in a single year, there would be a saving on the transportation costs.

Caterpillar

Caterpillar has mobile 5.2 MW, 13.8 kV gas turbines available for rent. For a 25 MW capacity, this would involve 5 Caterpillar machines. Refer to Appendix 9 for information on the Caterpillar machines. The following is a summary of rental costs provided by Caterpillar. The costs are based on 4 months rental duration for one site.

**Table 6B**
**Caterpillar Mobile Gas Turbine**
**2007 Rental Costs (Cdn$)**

| Description | Unit Cost | Total Cost (4 Months) |
|---|---|---|
| Caterpillar 5 MW GT – 4 Month Rental | | |
| o Rent 5 GT's = 25 MW Capacity | | |
| o Monthly rental (capacity charge) per GT | $105,000.00 | $2,100,000.00 |
| o Fired hours charge per GT per hour (Assume 1000 hours for 4 months) | $42.00 | 42,000.00 |
| o Mobilization & Consumables cost per GT | $16,000.00 | 80,000.00 |
| o Setup, Commissioning & Testing per GT | $106,000.00 | 530,000.00 |
| o Decommissioning Costs per GT | $48,500.00 | 242,500.00 |
| o Full Time Site Supervisor – 4 months | $10,000.00 | 40,000.00 |
| | | |
| **Caterpillar Sub-Total:** | | **$3,034,500.00** |
| o Costs to connect 5 GT's to existing 13.8 kV circuit breaker & step-up transformer (estimate) | | 50,000.00 |
| o Costs to connect Fuel supply piping (estimate) | | 7,500.00 |
| | | |
| **Total:** | | **$3,092,000.00** |

The costs in Table 6 are based on 5 gas turbines for 4 months duration. Obviously, if less than 5 machines are required and the alternator refurbishment duration is less than 4 months, the rental costs will be reduced. The costs in Table 6B apply to one site. If 5 rental units for 4 months are required for the second site, the costs will double.

Caterpillar can also provide a technician/operator 12 hours per day and on call for the remainder of the day at a negotiated rate per week.

## 7.6 OPTION 4 – NEW DYNAMIC VAR COMPENSATOR

The HYDRO RFP scope focused on what should be done to ensure the reliable operation of the Hardwoods and Stephenville Gas Turbines for a further 15 years of service. While the concept of replacing one or both of the Gas Turbines with another technology for MVAR support of

system voltage is beyond the scope of this Study, we are presenting the concept of dynamic var compensation for HYDRO's consideration only.

The Gas Turbines at both the Hardwoods and Stephenville sites operate primarily as synchronous condensers providing system voltage support on the eastern and western regions of Newfoundland. From information provided by HYDRO, the Gas Turbines at each site operate as synchronous condensers in excess of 90% of the running hours of the alternator. An option for HYDRO to consider would be the replacement of either one or both Gas Turbines with dynamic var compensators for system voltage support.

Since Hardwoods has many more operational hours than does Stephenville, the option presented in this Report for HYDRO's consideration is the replacement of the Hardwoods Gas Turbine with dynamic var compensation and retention of the Stephenville Gas Turbine. With the Holyrood Generating Station located in the eastern portion of Newfoundland, there is significant existing generation in the region served by Hardwoods. Components from the retired Hardwoods Gas Turbine can then be used as spare parts for the Stephenville Gas Turbine. In addition, elimination of the Hardwoods Gas Turbine would result in operational and maintenance savings.

American Superconductor Corporation of Wisconsin has developed a Dynamic VAR Compensation system that dynamically stabilizes and regulates voltage on transmission grids and industrial operations. The system denoted as D-VAR detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power at points of interconnection on the transmission or distribution grid. The variable output of the D-VAR device is typically the first source used to regulate voltage. As additional compensation is required, the D-VAR system will switch a capacitor bank (or reactor) in or out. At the exact moment of switching, the D-VAR device instantaneously injects (or absorbs) the same amount of VAR's as the capacitor bank, eliminating the step voltage change that would otherwise occur. The D-VAR system then resumes its normal voltage regulation mode, dynamically injecting or absorbing VAR's as required. Information provided by HYDRO on MVAR loadings at the Hardwoods site illustrates that the MVAR loadings at that site rarely exceed 25 MVAR with most loadings in the 10 – 20 MVAR range. D-VAR systems are flexible and scalable ranging from 2 MVAR to hundreds of MVAR.

The application of a D-VAR system at the Hardwoods site however would require an in-depth study with involvement by the D-VAR supplier. A system study would likely be involved to determine the size, configuration, terminal station interconnection requirements, operational requirements and costs of the D-VAR system. Such a study is beyond the scope of this Study.

This Study has not sourced capital costs associated with the supply and installation of a D-VAR system at the Hardwoods site for the reasons noted above. It is our opinion however that the costs associated with this option would be competitive with the other options outlined herein. A

ballpark estimate for a D-VAR system at Hardwoods would likely be in the range of $5-10 million. Stantec would be willing to undertake a more detailed study on this technologies potential application at HYDRO's discretion. Again, the application of D-VAR technology at Hardwoods is introduced solely for HYDRO's consideration. While some information on D-VAR technology, obtained from the Web, is included in Appendix 10, discussions with the D-VAR supplier are mandatory to obtain more detailed information on the potential application of this technology at Hardwoods.

Following the installation of the D-VAR system, the existing Gas Turbine could be retained with minor refurbishments for standby power generation purposes or disassembled with the components used as spare parts for the other site. There would be costs involved to dismantle the existing Gas Turbine, buildings, fuel storage tank and other infrastructure. These costs would be in addition to the figures presented in the preceding paragraph.

# 8.0 LIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS

## 8.1 GENERAL

The primary focus of the life cycle cost analysis aspects of the study involves an economic evaluation of the costs associated with the Base Cases and the various Options outlined in Section 7.0 ie refurbishing the existing units, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis includes capital costs for equipment supply and installation as well as operational and maintenance costs at each site.

The life cycle cost analysis of each Gas Turbine option was performed by using HYDRO's Cost/Benefit Financial Analysis Model. The HYDRO cost/benefit analysis template uses the Cumulative Net Present Value (CPW) approach to perform economic or financial analyses of alternatives as part of the justification of a project. For the purposes of this Study, the CPW approach compares the various options available for the Hardwoods and Stephenville Gas Turbines to provide reliable operation for a further 15 years.

## 8.2 FINANCIAL MODEL INPUT DATA/CRITERIA/COSTS

In discussions with HYDRO, it was agreed that the future operational mode of the Gas Turbines at each site, on an annual basis, will reflect to a large degree its annual operation over the past 5 years in terms of MW and MVAR output, operational and maintenance budgets. In a series of emails throughout October 2007, HYDRO provided the following Financial Model Input information. A copy of the various emails is included in Appendix 11.

### 8.2.1 MWHRS AND MVAR OUTPUT

The MWhrs loadings forecast for each Gas Turbine for the next 15 years is a very variable number as dictated by changing power system operational conditions. It was recommended in an October 26, 2007 HYDRO email (Email No. 1) to use 1200 MWhrs annually for each of the Hardwoods and Stephenville Gas Turbines. It is recognized this number could change significantly over the next 15 years.

A HYDRO email of November 2, 2007 (Email No. 2) provided daily MVAR loadings on each Gas Turbine over the period June 10, 2006 – November 1, 2007. The daily average for both Hardwoods and Stephenville was typically under 10 MVAR with occasional peaks up to 25 MVAR. It will be assumed that this MVAR mode of operation will continue for the next 15 years.

The synchronous condenser operating hours, over the past 5 years at each site, as advised in a HYDRO email of October 26, 2007 (Email No. 1), are as follows:

- Hardwoods – 15,512 hours or an average of 3102 hours annually
- Stephenville – 4,799 hours or an average of 960 hours annually

The average annual hours of synchronous condenser operation will be carried forward as the annual MVAR operating mode for the next 15 years.

### 8.2.2 Operations and Maintenance Budgets

HYDRO, in an email of October 24, 2007 (Email No. 3) provided the following information on Operations and Maintenance Budgets at Hardwoods and Stephenville over the period 2002 through 2006 with a forecast for 2007. These Budget costs exclude fuel costs.

**Table 7**
**Operational and Maintenance Costs**
**Hardwoods and Stephenville**
**(Excludes Fuel Costs)**

| Year | Hardwoods | Stephenville |
|---|---|---|
| 2002 | $178,000 | $83,000 |
| 2003 | $236,000 | $105,000 |
| 2004 | $114,000 | $175,000 |
| 2005 | $425,000 | $114,000 |
| 2006 | $486,000 | $355,000 |
| 2007 (Forecast) | $300,000 | $160,000 |
| | | |
| **5 Yr Ave (Excluding 2007)** | **$287,800** | **$166,400** |

The 5 year average will be carried forward, adjusted for inflation, as an annual operations and maintenance cost for the next 15 years.

### 8.2.3 Gas Turbine #2 Oil Fuel Price Forecast

HYDRO, in an email of October 11, 2007 (Email No. 4), provided a forecast of #2 Oil fuel prices per liter over the period 2008 through 2037. For the purposes of the options life cycle cost analysis exercise, the 15 year forecast costs between 2008 and 2023 will be used.

**Table 8**
**# 2 Oil Fuel Price Forecast (Cdn$/l)**
**2008 - 2023**

| Year | | Hardwoods | | Stephenville |
|---|---|---|---|---|
| | | | | |
| 2008 | | 0.624 | | 0.686 |
| 2009 | | 0.552 | | 0.613 |
| 2010 | | 0.557 | | 0.619 |
| 2011 | | 0.578 | | 0.640 |
| 2012 | | 0.606 | | 0.668 |
| 2013 | | 0.631 | | 0.694 |
| 2014 | | 0.666 | | 0.730 |
| 2015 | | 0.686 | | 0.752 |
| 2016 | | 0.721 | | 0.788 |
| 2017 | | 0.751 | | 0.820 |
| 2018 | | 0.786 | | 0.856 |
| 2019 | | 0.816 | | 0.888 |
| 2020 | | 0.847 | | 0.919 |
| 2021 | | 0.867 | | 0.941 |
| 2022 | | 0.882 | | 0.957 |
| 2023 | | 0.902 | | 0.979 |

These annual fuel forecasts will be carried forward to compute fuel costs at each site for the next 15 years.

### 8.2.4 Inflation and Escalation Forecast

HYDRO, in an email of October 26, 2007 (Email No. 5), provided a forecast of inflation and escalation for the period 2000 through 2027. The forecast, included in Appendix 11, provides forecasts for General Inflation, Electric Utility Construction Price Escalation (5 categories) and Operating and Maintenance Cost Escalation.

The figures for the period 2008 through 2023 will be used in the life cycle cost analysis of the various Gas Turbine options.

### 8.2.5 Fuel Consumption at Each Site

HYDRO, in an email of November 13, 2007 (Email No. 6) provided the following information on fuel consumption at Hardwoods and Stephenville over the period 2004 through 2007. The 2007 figures are for a partial year assumed to cover 9 months. The consumption numbers are as follows:

**Table 9**
**#2 Fuel Oil Consumption (litres)**
**Hardwoods and Stephenville**
**(2004 - 2007)**

| Year | Hardwoods | Stephenville |
|---|---|---|
| 2004 | 95,288 | 50,241 |
| 2005 | 433,380 | 147,566 |
| 2006 | 738,552 | 389,686 |
| *2007 (partial year)* | *262,691* | *204,485* |
| | | |
| 2007 (full year forecast) | 350,255 | 272,646 |
| **3 Yr Ave (Excluding 2004)** | **507,395** | **269,966** |

The 3 year average will be carried forward as an annual fuel consumption figure for the next 15 years.

## 8.3 SUMMARY OF GAS TURBINE FACILITY REFURBISHMENT CAPITAL COSTS

The following Table 10 is a summary of the capital costs of the Gas Turbine Facility refurbishments – Base Case and Options - presented in Section 7.0 of this Report, which will be the subject of the life cycle cost analysis exercise. As noted in the various Tables in Section 7.0, there are further costs, associated with a number of the options, primarily modifications to existing enclosures to accommodate new equipment that will require further detailed investigation by the new equipment suppliers.

**Table 10**
**Gas Turbine Facility Refurbishment Capital Costs**
**(2007 Costs)**

| Cost Analysis Alternatives | | Description | | Capital Costs (Cdn$) |
|---|---|---|---|---|
| | | | | |
| **Base Case** | | | | |
| 1A | | Refurbish Existing Equipment - Hardwoods GT<br>Allowance for Temporary Gas Turbine Rental (1) | | $4,506,880.00<br>3,307,500.00 |
| 1B | | Refurbish Existing Equipment - Hardwoods GT<br>No allowance for Temporary Gas Turbine Rental | | $4,506,880.00 |
| 2A | | Refurbish Existing Equipment - Stephenville GT<br>Allowance for Temporary Gas Turbine Rental (1) | | $4,538,883.00<br>3,307,500.00 |
| 2B | | Refurbish Existing Equipment - Stephenville GT<br>No allowance for Temporary Gas Turbine Rental | | $4,538,883.00 |
| | | | | |
| **Options** | | | | |
| 1 | | New Engines & Power Turbines – Refurbish<br>Balance of Equipment (2) – one site<br>Allowance for Temporary Gas Turbine Rental (1) | | $26,419,761.00<br><br>3,307,500.00 |
| 2 | | New Alternator / Exciter – Refurbish Balance of Equipment (2) – one site<br>Allowance for Temporary Gas Turbine Rental (1) | | $7,163,381.00<br><br>3,307,500.00 |
| 3 | | New Gas Turbine – Dismantle existing Gas Turbine and use as Spare Parts – one site | | $36,900,000.00 |
| 4 | | Dynamic Var Compensation – Ballpark estimate at this time as a more detailed study is required to define scope and costs | | $10,000,000.00 |

Note (1): The Gas Turbine rental covers a period of 4 months at the site.

Note (2): There are further costs associated with these options, primarily modifications to existing enclosures to accommodate the new equipment, which will require further detailed investigation by the new equipment suppliers.

## 8.4 LIFE CYCLE COST ANALYSIS ASSUMPTIONS AND COMMENTARY

A life cycle cost analysis of each option was performed using HYDRO's Cost/Benefit Financial Analysis Model. The following sub-sections provide an overview of the analysis, assumptions and other criteria. Commentary is provided on the financial analysis of each Gas Turbine Facility Option. A copy of the various Life Cycle Cost Analysis Model runs is included in Appendix 12.

For the purposes of this study, the following assumptions have been used throughout all of the options:

Initial project capital cost is incurred end of year 2008

- Annual costs (fuel and O&M) begin 2009
- Annual costs are escalated through 2023 using the default indices in the NLH financial analysis tool
- The average fuel consumption over the past three years has been used as the base case for projections of future fuel consumption at both the Hardwoods and Stephenville sites
- The 2007 project capital costs provided in Section 7.0 have been escalated to 2008 to determine the "Project In-Service Cost," using the built-in "Hydro and Thermal Plant Indices" escalation factors in the NLH financial analysis tool
- O&M costs have been assumed as 50% materials and 50% labour
- Cumulative net present values are expressed in January 2007 dollars

Each of the options described below were analyzed to determine the comparative cumulative net present value (CPW) over 15 years of operation. Note that two sub-cases were run for each scenario, in order to gauge the possible impact of future HYDRO maintenance requirements:

**Sub-Case #1:** Additional refurbishment costs are assumed to be required in 15 years, and are accounted for in the financial model as replacement costs occurring in 2023. Future refurbishment costs are adjusted to reflect the degree of work completed in 2008 for each option.

**Sub-Case #2:** It is assumed that equipment refurbished in 2008 will require replacement in 15 years. These costs are accounted for in the financial model as replacement costs occurring in 2023.

### 8.4.1 Base Case 1A – Hardwoods Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario considers refurbishment at the Hardwoods site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For

Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $16.0 million and $29.9 million for Sub-cases #1 and #2, respectively.

### 8.4.2 Base Case 1B – Hardwoods Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Hardwoods site (ie. identical to the Hardwoods base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $11.5 million and $26.9 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 1A illustrate the financial impact of rental unit expenses during refurbishment.

### 8.4.3 Base Case 2A – Stephenville Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario is for refurbishment at the Stephenville site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For

Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $13.8 million and $27.7 million for Sub-cases #1 and #2, respectively. Note that while the Stephenville refurbishment capital costs are similar to Hardwoods, the CPW is considerably lower due to Stephenville's lower utilization and fuel costs.

### 8.4.4 Base Case 2B – Stephenville Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Stephenville site (ie. identical to the Stephenville base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $9.5 million and $25.0 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 2A illustrate the financial impact of rental unit expenses during refurbishment.

### 8.4.5 Option No. 1 – Replacement of Engines and Power Turbines

This option is for replacement of the gas engines and power turbines, and refurbishment of the alternator and auxiliaries. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 90% of historical fuel consumption and 75% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new machines.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original alternator would still be in place at that time, and that the engines will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the alternator in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $15.8 million in 2023 dollars.

The estimated CPW of costs for this option is $33.1 million and $36.2 million for Sub-cases #1 and #2, respectively. This is one of the highest cost options, due to the high costs of the engine replacement which are incurred early in the project's life.

### 8.4.6 Option No. 2 – Replacement of Alternator and Exciter

This option considers replacement of the alternator, and refurbishment of the gas engines and power turbines. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 100% of historical fuel consumption and 80% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs will be improved by installation of the new alternator.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original engines would still be in place at that time, and that the alternator will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the engines in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $44.8 million in 2023 dollars.

The estimated CPW of costs for this option is $16.2 million and $28.6 million for Sub-cases #1 and #2, respectively.

### 8.4.7 Option No. 3 - New Gas Turbine Facility

This option is for installation of a complete new gas turbine, including engine, alternator and auxiliaries. The Hardwoods site is assumed as the base case. No allowance is included for rental equipment, as it is assumed that the new unit would be installed while the old system was still operational.

For projecting future annual costs, 90% of historical fuel consumption and 70% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new unit. A capital maintenance expense of $2.0 million in 2023 is allowed for both Sub-Cases.

The estimated CPW of costs for this option is $38.1 million for both Sub-cases #1 and #2. It is assumed that only routine major maintenance will be required in 2023.

### 8.4.8 Option No. 4 - Dynamic Var Compensation

Although this option requires additional investigation, a scenario was developed to gauge the potential of dynamic VAR compensation. No allowance is included for rental equipment, as it is assumed that the new equipment would be installed while the old system was still operational.

For future annual costs, it is assumed that fuel consumption will be eliminated and O&M costs will be reduced to 10% of historical.

With these assumptions, the DVAR option appears very competitive with the refurbishment options. The CPW of this option is $9.0 million, placing it ahead of all the alternatives. Additional work is required to further develop the technical and financial aspects of this option; however, it is evident that it deserves additional consideration.

## 8.5 LIFE CYCLE COST ANALYSIS RESULTS AND RANKING OF OPTIONS

The results of the life cycle cost analysis are summarized below in Table 11. In general, the refurbishment options are the least cost alternatives, regardless of the capital expenditure that is assumed to be incurred in 15 years time.

**Table 11**
**CPW of Alternatives**

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 1 | Option 4 – DVAR | $8,995,597 | $8,995,597 |
| 2 | Base Case 2B- Stephenville Refurbishment, No Rental Allowance | $9,548,569 | $24,996,028 |
| 3 | Base Case 1B- Hardwoods Refurbishment, No Rental Allowance | $11,467,914 | $26,930,650 |
| 4 | Base Case 2A- Stephenville Refurbishment with Rental Allowance | $13,842,768 | $27,711,405 |
| 5 | Base Case 1A- Hardwoods Refurbishment with Rental Allowance | $16,010,747 | $29,894,660 |

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 6 | Option 2 – New Alternator/Refurbish Engines & Turbines | $16,248,954 | $28,574,070 |
| 7 | Option 1 – New Engines/Refurbish Alternator | $33,088,681 | $36,221,835 |
| 8 | Option 3 – Complete New GT Unit | $38,145,919 | $38,145,919 |

Figures 1 and 2 provide a graphical summary of the options for Sub-Case #1. Note that the annual operating costs of each alternative have a relatively minor impact on life cycle costs compared to the required capital expenditures. This is due primarily to the ongoing projected synchronous condenser mode of operation of the Facilities over the next 15 years. If generation at each site should increase significantly in the next 15 years, O&M costs will increase accordingly. The lower O&M and fuel savings expected for the options where major equipment replacements are completed in 2008 therefore do not outweigh the early capital expenditure.

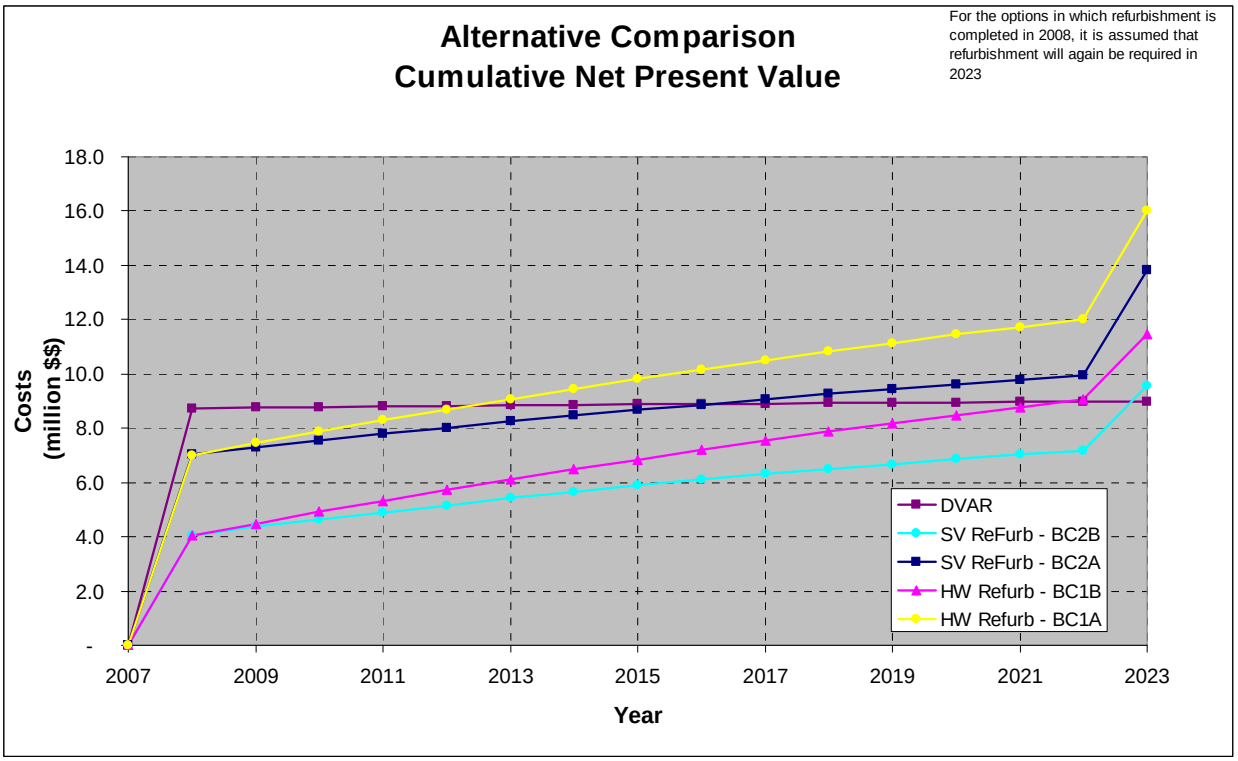



**Figure 1**
**Sub-Case #1 – Base Cases and DVAR Compensation**

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**FINAL REPORT**
**CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS**
**HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES**
7BLIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS
December 18, 2007

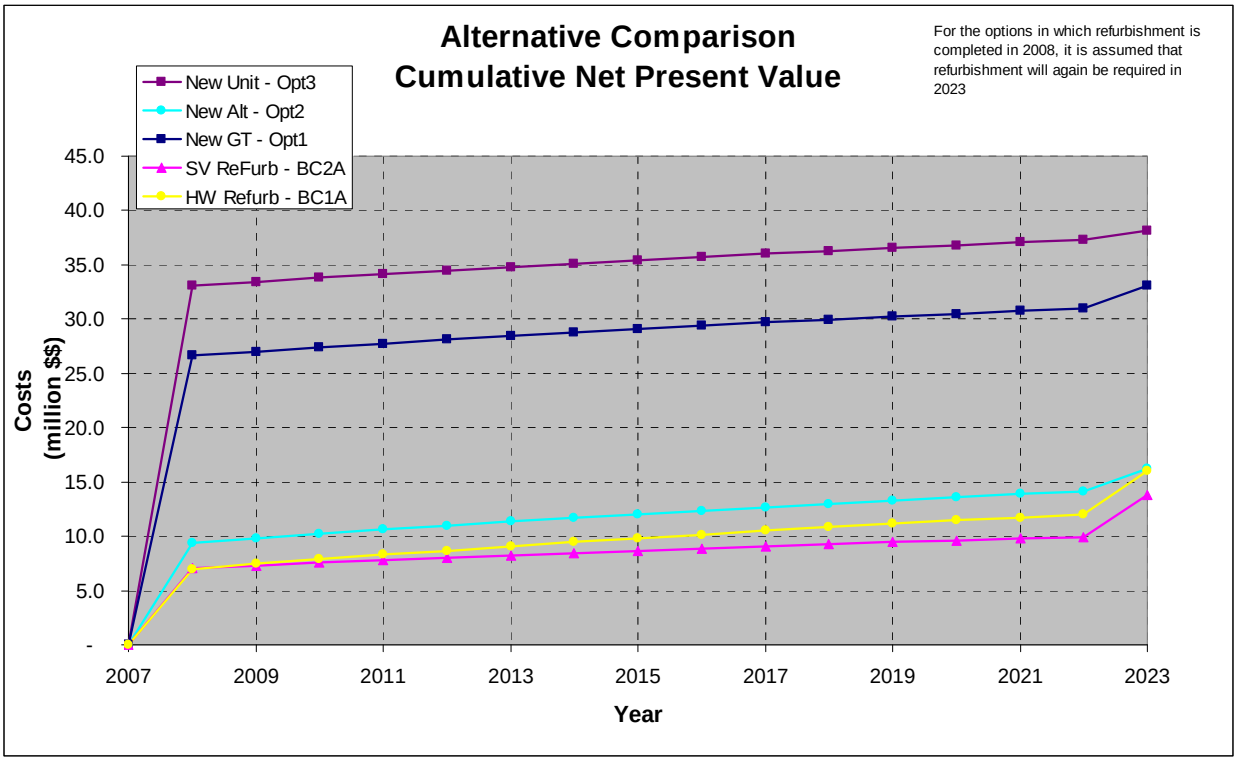



**Figure 2**
**Sub-Case #1 – Base Cases and Equipment Replacement Options**

# 9.0 CONCLUSIONS AND RECOMMENDATIONS

Stantec conducted a Condition Assessment and Life Cycle Cost Analysis Study of the Newfoundland and Labrador Hydro Hardwoods and Stephenville Gas Turbine Facilities over the period July through November 2007. The Gas Turbines at each site have been in service since the mid 1970's. The objective of the Study is to provide HYDRO with recommendations on the best course of action to achieve a high degree of operating reliability at each site, at least cost, for a further 15 years of operation.

The Study assessed the condition of equipment and structures at each site, Report Sections 5 and 6, and evaluated a number of potential options, Report Section 7, to achieve HYDRO's objective. The 15-year life cycle cost analysis and ranking of each option is summarized in Table 11 of Report Section 8. The Table is repeated here for convenience.

**Table 11**
**CPW of Alternatives**

| Ranking | Option | CPW (2007 Cdn$) | |
|---|---|---|---|
| | | Sub-Case #1 | Sub-Case #2 |
| 1 | Option 4 – DVAR | $8,995,597 | $8,995,597 |
| 2 | Base Case 2B- Stephenville Refurbishment, No Rental Allowance | $9,548,569 | $24,996,028 |
| 3 | Base Case 1B- Hardwoods Refurbishment, No Rental Allowance | $11,467,914 | $26,930,650 |
| 4 | Base Case 2A- Stephenville Refurbishment with Rental Allowance | $13,842,768 | $27,711,405 |
| 5 | Base Case 1A- Hardwoods Refurbishment with Rental Allowance | $16,010,747 | $29,894,660 |
| 6 | Option 2 - New Alternator / Refurbish Engines & Turbines | $16,248,954 | $28,574,070 |
| 7 | Option 1 – New Engines / Refurbish Alternator | $33,088,681 | $36,221,835 |
| 8 | Option 3 – Complete New GT Unit | $38,145,919 | $38,145,919 |

## Option 4

While Option 4, the D-VAR addition at one site, has the No. 1 ranking in the options considered primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. The question that HYDRO must address regarding this Option involves whether backup emergency generating capability is absolutely required at either site.

- ***Recommendation:*** *If the answer to the above question is yes, then dismiss this Option from further consideration. If the answer to the above question is no, then proceed with a more detailed study of this Option with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options for MVAR system voltage support only should HYDRO decide to forego generation capability at either site.*

## Base Case Options: 1A – 1B – 2A – 2B

The Base Case options of refurbishing the existing equipment including the gas generator engines, power turbines and alternator are ranked as follows:

- No. 2 Ranking – Stephenville refurbishment (Case 2B) with no allowance for a temporary mobile gas turbine rental. It is estimated that a 4 month outage would be required for an alternator major off-site refurbishment.
- No. 3 Ranking -- Hardwoods refurbishment (Case 1B) with no allowance for a temporary mobile gas turbine rental. It is estimated that a 4 month outage would be required for an alternator major off-site refurbishment.
- No. 4 Ranking – Stephenville refurbishment (Case 2A) with an allowance for an estimated 4 month mobile gas turbine rental to cover the outage period.
- No. 5 Ranking – Hardwoods refurbishment (Case 1A) with an allowance for an estimated 4 month mobile gas turbine rental to cover the outage period.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and structures can be refurbished sufficiently to allow reliable operation over the next 15 years. If HYDRO selects the Base Case refurbishment options, HYDRO will have to make a decision on whether to pursue a temporary mobile gas turbine rental arrangement with equipment suppliers or tolerate an estimated 4-month outage at each site. The rental costs used in the analysis are strictly budget figures provided by two equipment suppliers. Final rental costs could be more or less.

The existing balance-of-plant systems and equipment at each site are generally in good condition. This includes the mechanical fuel unloading and forwarding equipment; electrical equipment – transformer; switchgear; motor control; batteries; etc; control and instrumentation equipment – Bailey DCS equipment; instrumentation devices; etc. As discussed in Report Sections 4, 5 and 6, there is some degree of minimal refurbishment work required in these systems. Refurbishment recommendations are outlined in Report Appendix 6.

Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. A new alternator was assessed under Option 2.

- ***Recommendation:*** *The Base Case existing equipment refurbishment option at each site has the lowest CPW of the Options and is the recommended approach for HYDRO to pursue in order to provide a further 15 years of reliable service. The major unknown is the current condition of the alternator and whether it needs refurbishment or replacement in order to provide reliable service for a further 15 years. If replacement is required, then Option 2 should be pursued.*

## Option 2

Option 2, involving the procurement of a new alternator coupled with the refurbishment of the existing gas generator engines and power turbines, as well as other balance-of-plant equipment and structures has a No. 6 Ranking of the refurbishment options considered. While this Option could reduce the outage time that would apply to refurbishing the existing alternator off-site, a 4-month allowance for a rental gas turbine is included in this Option. Again, HYDRO would have to decide if the rental unit is required or an estimated 4 month outage at each site can be tolerated. This Option would involve major modifications to the existing alternator enclosure as well as tie-ins to existing auxiliary systems to accommodate the current design of alternator. While a ballpark estimate has been provided for these costs, the costs would have to be finalized following a more detailed investigation of the enclosure and other interfaces by the alternator supplier. This Option would provide a new alternator with a life span greater than 15 years.

- ***Recommendation:*** *As discussed above, this Option would likely only be pursued, if following a thorough electrical testing and visual inspection of the existing stator and rotor (rotor removed from stator), it is determined that alternator replacement is a better option than refurbishment to allow reliable operation for a further 15 years. Further review by the equipment supplier is required to confirm the final alternator costs.*

## Option 1

Option 1, the procurement of new gas generator engines and power turbines coupled with the refurbishment of the existing alternator, as well as other balance-of-plant equipment and structures has a No. 7 Ranking of the refurbishment options considered. Since the alternator is refurbished off-site in this Option, a 4 month allowance for a rental gas turbine is included in this Option. Again, HYDRO would have to decide if the rental unit is required or a 4-month outage at each site can be tolerated. This Option would involve modifications to the existing engines and power turbine enclosures to accommodate the design of new engines and power turbines

proposed. These costs are not included and would follow a more detailed investigation of the enclosure by the equipment supplier. This Option would provide new engines and power turbines with a life span greater than 15 years.

- ***Recommendation:*** *This Option should not be pursued due to its high CPW value as well as unknown additional costs to incorporate the engines and power turbines in the existing enclosures and connection to the alternator.*

## Option 3

Option 3, a complete new gas turbine, has a No. 8 Ranking of the refurbishment options considered. This Option would have the least impact on operations at either site as outage time to connect the gas turbine to the electrical grid via the existing 13.8/66 kV transformer would be minimal. An estimate is provided for demolition costs associated with removal of the gas turbine replaced by the new unit. This Option would provide a gas turbine with a 30 year life span with lower O&M costs.

- ***Recommendation:*** *This Option should not be pursued due to its high CPW value and the fact the existing equipment can be refurbished to provide reliable service for the 15 year period specified by HYDRO.*

A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023, the specified 15 years of further service, has not been determined by HYDRO at this time. The financial analysis results in Table 11 reflect two scenarios beyond 2023. The first scenario (sub-case 1) assumes further refurbishment work in 2023, whereas the second scenario (sub-case 2) assumes the equipment will be replaced in 2023 with new. The two scenarios do not affect the overall ranking of the Options.

# 10.0 CLOSURE

This Report was prepared for the sole benefit of Newfoundland and Labrador Hydro. The Report may not be used by any other person or entity without the express written consent of Stantec Consulting Ltd (“Stantec”) and Newfoundland and Labrador Hydro.

Any use which a third party makes of this Report or any reliance on decisions made based on it, are the responsibility of such third parties. Stantec accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions taken based on this Report.

The information and conclusions contained in this Report are based upon work undertaken by trained professional and technical staff in accordance with generally accepted engineering practices current at the time the work was performed. Any site-specific information and documentation provided by other parties and used or referenced by Stantec has been assumed by Stantec to be accurate. Conclusions presented in this Report should not be construed as legal advice.

This condition assessment and life cycle cost analysis study was undertaken exclusively for the purpose outlined herein. This work was specific to the Hardwoods and Stephenville sites. The Report cannot be used or applied under any circumstances to another location.

# ENGINEERING CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS

## HARDWOODS & STEPHENVILLE GAS TURBINE FACILITIES

# APPENDICES

# APPENDIX 1
# MINUTES OF STUDY KICK-OFF MEETINGS
# HARDWOODS AND STEPHENVILLE

# APPENDIX 1
# MINUTES OF STUDY KICK-OFF MEETINGS
# HARDWOODS AND STEPHENVILLE

# Project Team - Stephenville and Hardwoods Condition Assessment
## July 26, 2007

| Name | Title | Phone | E-mail |
|---|---|---|---|
| ***HYDRO*** | | | |
| Nelson Seymour PROJECT MANAGER | Manager – Mechanical Engineering | 709-570-5902 | nseymour@nlh.nl.ca |
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| Bob Woodman | P&C Engineer | 709-737-1433 | bwoodman@nlh.nl.ca |
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| Dave Hicks | Electrical Engineer | 709-737-1244 | davehicks@nlh.nl.ca |
| Frank Ricketts | Manager – Environmental Services | 709-737-1708 | fricketts@nlh.nl.ca |
| Jim Wheeler | Asset Specialist – Generation and Terminals | 709-258-2331 | jwheeler@nlh.nl.ca |
| Kevin King | Electrical Engineer | 709-737-1353 | kevinking@nlh.nl.ca |
| Len Patey | Mechanical Maintenance "A" Stephenville | 709-643-2158 | lpatey@nlh.nl.ca |
| Ray Rowe | Electrician/Operator Stephenville | 709-643-6476 extension 238 | rrowe@nlh.nl.ca |
| Steve Carter | Production Supervisor | 709-258-2343 | scarter@nlh.nl.ca |
| Tony Chislett | Civil Engineer | 709-737-1737 | tonychislett@nlh.nl.ca |
| Trent Carter | Ecologist | 709-737-1955 | tcarter@nlh.nl.ca |
| Wayne Snow | Electrician/Operator Hardwoods | 709-687-0086 | waynesnow@nlh.nl.ca |
| ***Neill and Gunter*** | | | |
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| Brian King | Mechanical Engineer | 902-434-7331 | bking@ngns.com |
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| David Conrad | Controls and Instrumentation Engineer | 902-434-7331 | Delete from List |
| James Batt | Manager - Mechanical Engineering | 902-434-7331 | Delete from List |
| Jean Marc St. Pierre | Controls and Instrumentation Engineer | 902-434-7331 | jstpierre@ngns.com |
| Mark Reynolds | Civil/Structural Engineer | 902-434-7331 | mreynolds@ngns.com |
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| Robin Sipe | Turbine Assessment Specialist – S&S Turbine Ltd | 250-785-5272 | rsipe@bluenova.ca |

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# NOTES OF MEETING

## Kick-off Meeting
## Hardwoods & Stephenville Gas Turbines Condition Assessment

**Date:** 2007-07-17/18
**Location:** NLH Office Stephenville, NL

**Present:** **For Newfoundland and Labrador Hydro**

| | Position | Initials |
|---|---|---|
| Nelson Seymour | Mgr Mechanical Eng. | NS |
| Jim Wheeler | Asset Specialist | JW |
| Ray Rowe | GT Operator | RW |
| Stephen Carter | Production Super | SC |
| Len Patey | Mech. Maintenance | LP |
| Bob Woodman | Maintenance Project | BW |
| Dave Hicks | Electrical Eng. | DH |

**For Neill and Gunter (Nova Scotia) Limited**

| | | |
|---|---|---|
| Brian King | Lead Mech. Eng | BK |
| Mark Reynolds | Civil Eng. | MR |
| Alan Wong | Electrical Eng. | AW |
| Jean Marc St. Pierre | C&I Eng. | JMS |
| Robin Sipe (S&S Turbine Services) | Turbine Specialist | RS |
| Bill Hearn | Project Manager | BH |

**Purpose:** **Kick-off Meeting – Gas Turbines Condition Assessment**

**Day 1 – July 17, 2007**

**Action By**

**1. Introductions**

Introductions were made. NS pointed out that NLH's Craig Warren (Controls) and Tony Chislett (Civil – structural & oil tanks) were not able to attend the Meeting due to other commitments; however both could be contacted via telephone at a later date. NS also noted that Frank Ricketts (St. John's) could be contacted on GT Environmental issues as well as Operating Permit criteria.

While the Meeting focused on the Stephenville Gas Turbine (GT), there were numerous references to the sister GT at the Hardwoods site in St. John's. NS noted that Engine/Power Turbine B was

currently on Outage and available for Inspection later in the day. Engine/Power Turbine A would be available for Inspection on July 18.

**ACTION 2.** **General Discussion**

General discussion on the Study scope and GT issues ensued. Major issues noted by NLH included:

- Reliability – Remote starts on an as required basis are not always successful. More success if preparatory work done prior to start as per local manual starts. A random list of sporadic problems contribute to many of the unsuccessful starts – fuel supply; vibration problems; clutch problems (possibly proximity switch, valve or controls rather than mechanical issues); anti-icing valve issues. (Prior to the Meeting NLH had provided a multi-page email outlining typical start-up problems experienced at each Site over the past 1.5 years). Some of these problems may be an issue on one start up and not on the next.

- Anti-Icing Issue – There appears to be some uncertainty as to whether the anti-icing device has ever operated, as well as uncertainty on the control mechanism to operate the valve. Is there a detection system to operate the valve? RS will check to see if probes are there. RS noted that when the anti-icing valve is in operation, the GT thermal efficiency could be reduced as much as 1-1.5%. It may be necessary to replace the anti-icing system.

- A new Bailey Control System was installed at each Site in 1997 to replace the original GT control system. Noted there was little data storage and trending capability in the Bailey System; OEM support service was not good; logic changes have been made by NLH over the ensuing years. Number of monitoring points for remote operation from the ECC in St. John's is limited.

- There are issues with the vibration & temperature monitoring systems; availability of spare parts; etc.

- Glycol Cooling Issues – (i) Presently the Glycol Cooler associated with Generator cooling system is out of service. A Generator high temperature alarm prompted the action. The Glycol Cooler will be out of service until the problem is resolved. In the interim, outside air (sometimes moist, possibly salty) is admitted through the Generator access

| | |
|---|---|
| **ACTION** | doors. (It was noted that the Hardwoods GT uses air directly for cooling purposes); (ii) The Glycol Coolers for Generator and lube oil cooling are showing signs of corrosion. In fact the Lube Oil Glycol Cooler corrosion is well advanced and in need of immediate short term repair. (It was noted that the bottom pads of the lube oil Glycol Cooler at Hardwoods had been replaced) and (iii) The condition of the buried piping between the Glycol Coolers and the GT is unknown at this time. |
| | ▪ Exhaust stacks – The Stephenville stacks were replaced in 1992. (i) There are known cracks in one and possibly both stacks; (ii) Stack access, particularly around the snow doors, was identified as an issue – need for additional ladders and platforms. (It was noted that the original stacks are in place at Hardwoods); (iii) there have been issues with the pistons on the snow doors at Stephenville not allowing the snow doors to open; (iv)The access hatches to the Exhaust stacks were noted by NLH to be very small as well as bolted shut. This design results in an Area Classification of "confined space". NLH would like to see hinged access doors instead so that they can enter without resorting to extensive safety requirements. |
| | ▪ Air intake structures should have screens. |
| | ▪ GT enclosure door windows -- Viewing windows in a number of enclosure doors was identified as an issue of not being able to identify if there is a fire or safety problem prior to gaining access. |
| | ▪ The exhaust stack silencers appear to be performing well. |
| NG | ▪ Fuel Forwarding Building – (i) the floor is approximately 3 feet below grade. There is a question of whether this area should be considered as a "confined space area". The GT uses #2 Diesel Oil. NG will investigate the following codes and provide an opinion:<br>o API 500 – Division Classifications<br>o API 505 – Zone Classifications<br>o NEPA 497 – Class 1 Hazardous Locations Classification<br><br>(ii) An issue with the metering on the Fuel Forwarding skid was noted. |
| | ▪ The buried fuel oil supply piping between the Fuel |

| | |
|---|---|
| **ACTION** | Forwarding Building and the GT is planned to be replaced this year. The piping will be placed in a trench in accordance with current Environmental Protection Codes. |
| | ▪ NLH is of the opinion there may be a problem with the regulating valve on the fuel inlet to the Engines. |
| | ▪ An Inergen fire suppression system has been installed at various locations on the Site – Generator / Engine / Fuel Forwarding Building. There however is no such system installed in the Control Building Electrical Equipment Room. |
| | ▪ It was stated by NLH that corrosion was found on the lube oil coolers in the machine. RS noted that when a peaking GT does not run long enough to boil off any moisture/water in the lube oil system (say less than 2 hours), there can be corrosion problems in the bearings as well. |
| | ▪ Wiring termination boxes -- NLH noted there is corrosion in a number of terminal boxes around the GT enclosures. RS noted that JB's should not be mounted directly on the Engine – can be impacted by vibration. |
| | ▪ Engine wash system – NLH noted that this system was rarely (perhaps never) used for years. RS noted that washing on line was not effective and suggested that an off-line wask/soak at low rpm was the best approach. |
| | ▪ A new enclosue had been placed over the Generator output bus duct as a result of a phase to phase flashover problem experienced in the past. |
| NLH | ▪ GT spare parts are mainly located at the Hardwoods Site. BK asked if there was an inventory list? If yes, NLH was requested to provide a copy of the list. |
| | ▪ The Generator AVR at Hardwoods was replaced last year. There is currently a budget item (subject to approval) to do the same at Stephenville in the near future. |
| | ▪ Safety issues – NLH stated there should be (i) a railing on top of the Generator enclosure as the protective coating can be slippery at times; (ii) a platform under the door to the Generator heat exchanger as well as a viewing window in that door. |

ACTION

**3. Documentation**

NLH

WH tabled a Documentation List (copy attached) listing reports, drawings and other documentation that NG would like NLH to provide as part of the Condition Assessment Study. The NG List applies to both Gas Turbine Sites. NS also tabled a list of NLH documentation available at this time (copy attached). Also attached is a list of drawings and other documentation that NG currently has at its Dartmouth office. The three items listed are in Appendix 1 – Documentation Lists.

**4. NG Audit Check List**

WH tabled for information an NG Audit Check List that would be the basis of the Condition Assessment Study. A copy of the List is attached as Appendix 2. There was no discussion on the List.

NLH

On an operational issue, NG will need to know the pattern of use that is made of the two Gas Turbines in terms of the annual number of start/stop cycles and for what purpose – synchronous condenser or MWh production.

**5. Costing Information**

NLH

As part of the life cycle cost analysis portion of the Study, BK asked that NLH make available their cost data for operation & maintenance for each of the 50 MW GT Plants on an annual basis. BK also asked if NLH had researched and called for pricing on the replacement of one of the 50 MW GT Plants.

**6. Slides Presentation**

JW provided commentary on a Slide presentation of pictures taken at the Stephenville Site. NLH provided a CD of the photos to NG.

**7. Site Visit**

NG visited the Stephenville Site in the afternoon in the company of the NLH personnel. Engine/Power Turbine B and the Generator were available for inspection, as well as the various auxiliary systems. RS conducted a borescope inspection of Engine B. Following the inspection, Engine/Power Turbine B and the Generator were run up to speed and synchronized to the grid. The startup was successful. A vibration alarm on the exciter was observed. The Generator was loaded to approximately 5 MW for

demonstration purposes. The intent was to place the Generator in synchronous condenser mode for the balance of the day. Two observations were noted: (i) the exhaust from stack B on startup was quite dirty indicated unburned hydrocarbons and (ii) the vibrations in the ground around the B side of the Gas Turbine were quite pronounced. This raised the question of when the shaft alignment was last checked and that it should be done again.

Workmen were active on repairs to the lube oil glycol coolers support structure. It was observed that the fins on both glycol coolers appeared to be coated with a grey dust that would likely impair heat conduction. The suggestion was made that some sort of cleaning should be implemented such as steam or chemical washing (HVAC Condenser Cleaning specialists would be a logical area to explore).

Prior to cleaning, it would be useful to collect some temperature data on glycol in/out; air in/out and lube oil in/out when the systems are in operation before and after cleaning. If some temporary system for glycol flow measurement could be installed, this would provide very useful data for future testing.

It was noted there is only one glycol circulating pump for the main lube oil system. There ought to be a replacement pump in NLH spares inventory as a backup to both Sites.

NG mechanical, electrical, Controls and civil personnel toured the Site making observations of the condition of the Gas Turbine and the auxiliary systems.

## Day 2 – July 18, 2007

### 8. Documentation

NLH

The NG Documentation List was extensively reviewed. NLH will assign personnel to locate and provide the documentation currently outstanding. It was agreed that a target date for assembling this information (both Sites) will be August 15, 2007. The information will be provided to NG in advance of the visit to the Hardwoods Site, tentatively planned for w/o August 20th.

### 9. Site Visit

NG's MR spent the morning on the Site to review/inspect Civil items not looked at on Day 1. Other NG personnel spent the morning at the NLH office discussing documentation as noted in

Item 8.

All NG personnel visited the Site in the afternoon. Engine/Power Turbine A was available for inspection. NG decided to have RS remain at Site in the afternoon to carry out borescope and other inspections on Engine/Power Turbine A. NG further decided, with the exception of RS, to cut short the intended 3 day visit to Stephenville for several reasons: (i) NLH had agreed at the morning Meeting to locate the outstanding documentation (Item 8) and have it available for August 15th – (the NG proposal was based on NLH providing the requested documentation in advance of the Kick-off Meeting); (ii) the 3 days was a guesstimate of time required on the Site – (the NG proposal was based on one full day visit per Site) and (iii) NG personnel were of the opinion they had inspected the equipment, with the exception of Engine/Power Turbine A, sufficiently and it would not be cost effective for NLH to have all NG personnel remain on Site for an additional day.

On Day 2, the Generator was running in synchronous condenser mode absorbing 19 MVAR.

**Minutes Prepared By:**
Bill Hearn

# APPENDIX 1
# DOCUMENTATION LISTS

NG

Neill and Gunter

DESIGN AND CONSULTING ENGINEERS

# FINAL -----

**2007-07-13 --------- Rev 2**

# GAS TURBINE CONDITION ASSESSMENT DOCUMENTATION LIST

## General

1.1 Gas Turbine Facility Maintenance Records (all equipment)
1.2 Gas Turbine Facility Operational Logs
- Forced Outage Information

1.3 Gas Turbine Facility Major Overhaul Reports (all equipment)
1.4 Inspection Reports (all equipment over past 10 years)
1.5 Test Reports (all equipment over past 10 years)
1.6 Site Layout Drawing
**1.7 Other**

## Mechanical

### 2.1. Gas Turbine

2.1.1 Gas Turbine Drawings and O&M Manuals on:
- Gas Turbine Equipment – engine; power turbine
- Fuel Forwarding Module
- Control Module
- Air Intake Structure
- Exhaust Stacks

2.1.2 Gas Turbine Boroscope Inspection Reports
2.1.3 Maintenance Scheduling Planned
2.1.4 List of major Gas Turbine Spare Parts at Site
2.1.5 List of existing parts/service providers for gas turbine equipment
2.1.6 Oil Analysis Reports
**2.1.7 Other**

## 2.2 Mechanical Auxiliary Systems

2.2.1 Drawings and O&M Manuals on:

- Fuel Oil Unloading Equipment
- Fuel Oil Storage Tank(s) and Piping System
  - Records of Internal & External Inspections
  - Inspection Checklists
  - NDT Examinations
  - Piping System
    - Original Design Information
    - Record of any Upgrades
    - History of Leaks/Spills
- Compressed Air Equipment
- Glycol Equipment
- Lube Oil Equipment

**2.2.2 Other**

# Electrical

## 3.1 Before Site Meeting (if possible)

3.1.1 Electrical Single Line Diagram
3.1.2 Protection and Control Single Line Diagram

## 3.2 During and After the Meeting

3.2.1 O&M Manuals & Drawings for:

- Generator
- Excitation System
- Generator Output Bus Duct
- Switchgear and Breaker
- Motor Control Centre
- Motors
- AC Distribution System (Station Service and Transfer Switch)
- DC Distribution System (Battery and Charger)
- Relays (relay spec sheets)

3.2.2. Test Reports on tests carried out on the equipment listed in Section 3.2.1.
3.2.3 Maintenance Records on equipment listed in Section 3.2.1
3.2.4 Equipment Addition and Replacement Records
3.2.5 Protection and Control Tripping Logic Diagram

3.2.6 Equipment and Grounding Layout
3.2.7 List of major equipment spares at Site
3.2.8 List of existing parts/service providers for power equipment
**3.2.9 Other**

## Instrumentation & Control

### 4.1 Before Site Meeting (if possible)

4.1.1 Control System Architecture including communication links
4.1.2 Equipment layout drawing with control panels and equipment identified
4.1.3 P&ID's

### 4.2 During and After the Meeting

4.2.1 List of component model and part numbers for each control system -Controllers, I/O cards, communication cards, power supplies, FTA's
4.2.2 Programming software and platforms per control system
4.2.3 I/O type and count per system
4.2.4 List of Field Instrumentation devices (flow switches, pressure switches, etc) c/w supplier and service information
4.2.5 SCADA system information
4.2.6 List of known problems and proposed remediation
4.2.7 Control system maintenance records c/w control component replacement frequencies
4.2.8 List of control system spares at Site
4.2.9 List of existing parts/service providers for control equipment
**4.2.10 Other**

## Civil

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July 17th/07

# NLH Documentation:

Format

(1) Hardwoods Gas Turbine Control System — Binder
- Elsag Bailey -- 1997

(2) Hardwoods Gas Turbine In House Training — Binder
- Owner: Howard Richards (NLH-P&C)

(3) Combustion Turbine Control System Description
- Provided by Craig Warren (NLH-P&C)
- Four 8½x11 pages plus 6 drwgs.

(4) Hardwoods & Stephenville Gas Turbine — Binder
Work Order Histories.

(5) Stephenville Drawings — Drwgs
- Total of 15 (Mech. & Civil)

(6) Stephenville G/T Plant Manual — Binder
- Produced by FERD Engineering
- Owner; Alberta Marche (NLH-Mech.)

(7) Stephenville Plant O&M Manuals — Several Binders & also in electronic format
- As originally provided by Curtis Wright

(8) Gas Turbine Plant Inspection Sheets
- Daily — Paper copy
- Weekly — "
- Semi-Annually — "
- Annual — "
- 5 yr Inspection — "
- P&C Six Year — "
- Gas Turbine Test Run — "
- Metal Clad Switchgear — "

(9) Boroscope Report - Svl & Hwds G/T's — electronic
- Produced by Alba Power - June/07

| | |
|---|---|
| Revision 0 --- July 24, 2007 | |
| | |
| STEPHENVILLE GAS TURBINE SITE | |
| DRAWINGS / DOCUMENTATION PROVIDED BY NLH | |
| | |
| **1. DRAWINGS** | |
| | |
| **Drawing No.** | **Title** |
| B1-319-C-64 | SGT - Tank Farm Site Layout |
| B1-319-C-65 | SGT - Tank Farm Miscellaneous Sections & Details |
| F-319-C-29 | SGT - Tank Farm External Piping Support Details |
| 3965-E-319-M-7 | SGT - Tank Farm Piping Arrangement |
| | |
| F-319-C-24 | SGT - Fuel Pumphouse Foundation & Details |
| 3965-E-319-M-6 | SGT - Fuel Pumphouse Piping, Plan & Sections |
| 3965-E-319-M-5 | SGT - Fuel Oil System Flow Diagram |
| F-319-M-2 | SGT - Fuel Oil System Profile & Location Plan |
| | |
| B1-319-M-13 | SGT - Glycol Cooler Structural Details & Water Drain |
| A1-319-M-014 | SGT - Standby Diesel Building & DG Installation |
| | |
| F-319-C-52 | SGT - Building Alterations & Miscellaneous Details |
| A0 - 319-C-47 | SGT - Foundation Layout |
| D-319-C-31 | SGT - Sump Layout & Details |
| | |
| A2-319-M-11 | SGT - Caged Ladder and Catwalk Assembly on Exhaust Stacks |
| A2-319-M-12 | SGT - Caged Ladder & Catwalk Details |
| | |
| B1-374-E-007 | SGT - Transducers, Speed Repeaters Aand Misc. Panel Services Schematic |
| B1-374-E-008 | SGT - Vibration Monitoring Equipment Wiring Diagram |
| B1-374-E-010 | SGT - Generator-Transformer Metering And Protection |
| B1-374-E-011 | SGT - Voltage Regulator Schematic |
| B1-374-E-027 | SGT - DCS Topology |
| B1-374-E-028 | SGT - DCS Racks Layout |
| | |
| | |
| | |
| **2. DOCUMENTS** | |
| | |
| 1 | Curtis Wright Hardwoods GasTurbine Manual (provided on CD) |
| 2 | Alba Boroscope Report on Engines at Hardwoods & Stephenville |
| 3 | Photos of Stephenville Gas Turbine (provided on CD) |
| 4 | Stephenville GT Station Log Extractions --- 1992 - 2006 |
| 5 | Stephenville GT Station Work Order Extractions --- 1999 - 2006 |

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# NOTES OF MEETING

## Kick-off Meeting
## Hardwoods Gas Turbine Condition Assessment

**Date:** August 21, 2007
**Location:** HYDRO Office, St. John's

**Present:** **For Newfoundland and Labrador Hydro**

| | Position | Initials |
|---|---|---|
| Nelson Seymour | Mgr Mechanical Eng. | NS |
| Jim Wheeler | Asset Specialist | JW |
| Andrea MacDonald | Mechanical Eng. | AM |
| Greg Read | Mechanical Eng | GR |
| Stephen Carter | Production Super | SC |
| Tony Chislett | Civil Engineer | TC |
| Bob Woodman | P&C Engineer | BW |
| Amanda O'Brien-Pilgrim | Electrical Eng. | AOP |
| Kevin King | Electrical Engineer | KK |
| **For Neill and Gunter (Nova Scotia) Limited** | | |
| Brian King | Lead Mech. Eng | BK |
| Mark Reynolds | Civil Eng. | MR |
| Alan Wong | Electrical Eng. | AW |
| Jean Marc St. Pierre | C&I Eng. | JMSP |
| Robin Sipe (S&S Turbine Services) | Turbine Specialist | RS |
| Bill Hearn | Project Manager | BH |

**Purpose:** **Kick-off Meeting – Gas Turbines Condition Assessment**

**Day 1 am – August 21, 2007**

**Action By**

1. **Introductions**

Introductions were made. NS pointed out that HYDRO's Craig Warren (Controls) was not able to attend the Meeting due to other commitments. Wayne Snow – Hardwoods Operator – will be available at site for questions.

NG informed HYDRO that an offer has been made by Stantec to buy NG. Stantec is a Canadian engineering firm headquartered in

**Action By**

Edmonton. Stantec has approximately 7000 employees located in 90 plus offices throughout North America. If the offer is accepted by NG shareholders, a closing could occur in October 2007.

2. **Outage Situation**

NS stated that the Unit was currently operating in synchronous condenser mode and likely will be operating in that mode during the 2 day site visit. An outage has been taken out on Engine/Power Turbine A which will be available for Inspection later in the day. The plan is to take out an outage on Engine/Power Turbine B which will be available for Inspection on Wednesday August 22nd.

3. **Roundtable Discussion on Hardwoods GT**

General roundtable discussion took place on the equipment, buildings and structures at the Hardwoods GT site

3.1 Gas Generators (Engines)

The A Engine has never been overhauled since installation in 1976. The B Engine was last overhauled in 1993.

The Alba June 2007 Borescope Inspection Report was referred to. NS reported that due to the deteriorated condition of Engine A, it has been placed on restricted operation for emergency use only. The Alba inspection found Engine A to have extensive corrosion on various components, as well as damage to a number of blades on the HP section. Engine B was also found to have extensive corrosion, as well as a spacer missing in the HP section which threatens the structural integrity of the unit. Combustor cans on both Engines were showing signs of corrosion and cracks.

NS

In light of the condition of the Engines, RS suggested an option for HYDRO's consideration. RS has a spare engine and starter assembly currently available at the S&S Turbines shop. HYDRO to consider the option.

RS stated that the burner nozzles should be cleaned on a regular basis. There is an ultrasonic cleaner on site. RS suggested that the maintenance technicians should be given instruction on how to properly clean the burners. RS noted there are two styles of nozzles at Stephenville – old style (non-welded) which is easy to take apart and a new style nozzle which is welded and more difficult to take apart.

RS suggested that HYDRO should have a clean spare set of

nozzles available for placement in the Engine when EHT problems occur.

NS/JW commented that some work was done on the air inlet system over the years. There is information regarding this work on the Information CD assembled by HYDRO (see section 4).

**Action By**

3.2 Power Turbine Components

NS/JW stated there had been a series of modifications made to the Curtiss Wright turbines in 1988 (similar changes were made at Stephenville). It was noted that the units were prototypes when installed and ultimately needed design modifications. There is a Report on the work carried out on the Information CD. At this time, there appears to have been no significant work done on the power turbines over the past 20 years.

RS In response to a NS query, RS will do some research on service providers for the power turbines as well as anyone stocking spare parts for the turbines.

RS RS noted that thrust bearings are available in the marketplace. Main shaft bearings can be fabricated. Similarly, blades can be manufactured as well. RS stated that if spare blades are available, S&S Turbines can use the blades to make castings. RS will do further research on blading.

There was some discussion on deflector rings disengaging and flying out the exhaust stacks. The mounting system was briefly discussed. FERN Engineering came up with a procedure in the late 1980's for installing the rings. JW noted there have been multiple revisions to the procedure with little success in keeping the deflector rings in place. SC added that the problem goes back 5-6 years with increasing frequency of deflector ring problems over recent years. RS noted that a different mounting system may be needed. No resolves to the problem at the meeting.

3.3 Exhaust Stacks

Work was done on the Exhaust Stacks in 1992. (Stephenville was worked on in 1989. The existing Hardwoods interior silencer panels were revised when the work was carried out. NS was not aware of exhaust stack cracking problems at Hardwoods similar to the situation at Stephenville. JW noted there was an issue in 2006 with the silencer panels. The panels are bolted to the wall of the stack and had dropped down several inches. There were re-aligned by a contractor and appear to be ok now. (There are no known problems

at Stephenville regarding silencer panels moving).

The snow doors were redesigned in the mid 1980's. The actuator was changed from electric to pneumatic operation. No major problems with the snow doors. JW stated that the pneumatic actuators are to be replaced in near future.

**Action By**

3.4 Clutches

NS stated there have been no significant clutch problems over the years. Problems that have occurred have related more to peripheral devices – sticking valves in control system; proximity switches, etc. Uncertain as to whether the clutches were ever disassembled at Hardwoods (noted that a Stephenville clutch was taken apart once – year uncertain).

3.5 Bearings

NS was not aware of any bearing related problems at Hardwoods or any work having been performed on the bearings.

3.6 Lube Oil System & Cooling

The lube oil system is original equipment. There had been a lube oil leak around the bearings, filling a sump with oil. Other than that, NS was not aware of any other problems on the lube oil system.

There is a glycol cooler on the lube oil system (similar to Stephenville). While age and deterioration is an issue, the equipment is in better physical condition that the glycol cooler at Stephenville. In 2006, a new bottom was retrofitted to the cooler. Everything else on the cooler is original equipment, including the piping. The cooling fins have not been cleaned. A new 3 way modulating valve was installed in 2006. No temperature problems known on the lube oil system.

3.7 Enclosures

NS stated that nothing much was done to the engine / power turbine / alternator enclosures over the years. There is a major paint job planned but is on hold.

3.8 Alternator / Excitation System

NS reported that efforts are underway to collect test and other information on the alternator. Key individuals are Robert Stoyles – P&C supervisor for NL east coast (Hardwoods GT) and Clifton

AM — Quinton – P&C supervisor NL central (Stephenville GT). Information should be available in next 2-3 weeks.

AM — KK reported having seen some information on rotor work carried out in early 1990's. (Note – while at site on Day 2, AM had a file on work carried out on the alternator in the early 1990's and late 1980's. AM to provide copies of two Reports contained in the file.

There have been alternator vibration problems which seem more related to the B end of the unit.

The alternator is air cooled (no glycol cooling system as was the case at Stephenville). Ambient air is sucked in, via filters, on one side of the enclosure and discharged on the other. The filter arrangement has been redesigned (not per original).

**Action By**

3.9 Fuel Unloading & Storage

The fuel unloading system is the original equipment – pumps, valves and piping. The system was reported to work well. JW noted a regulatory compliance issue associated with the fuel oil meters – appears to be difficulty in reconciling fuel usage versus what has been placed in the storage tank within the required percentage allowed by the regulations. HYDRO is working on the issue.

There were originally 2 storage tanks. One has since been removed. A storage tank upgrade was undertaken in the mid 1990's. The tank was cleaned and inspected. The dyke around the tank was redone at that time including the placement of a new liner. A Report on the scope of the work performed is contained on the Information CD.

BK & MR — JW noted that HYDRO engineers have been asked to define a recommended frequency for inspecting the storage tank internally plus a detailed plan for confirming the integrity of the dyke and liner. The plan is required by 2008. JW queried if there is anything Neill and Gunter can refer to in the Report regarding these matters.

MR stated that numerous factors must be considered when assessing the condition of a fuel oil storage tank. These factors can be different at different sites and all have an impact on the frequency for doing internal tank inspections. Factors include – age of tank; type of fuel stored in tank; drawdown rates; location of tank and its environment; etc. The bottom 1/3 of the tank requires special attention.

There is currently a 6 inch pipe that runs between the storage tank

and the fuel forwarding module adjacent to the GT. HYDRO plans to replace this pipeline either fall of 2007 or in 2008. NS stated the pipe may be reduced in size to 4 inch. HYDRO is considering a means of secondary containment either (i) use a smaller diameter pipe within a larger pipe or (ii) place the pipe in a trench. MR offered to do some research on the methodology other Neill and Gunter clients use to transport oil via pipelines..

MR

**Action By**

3.10 Fuel Forwarding Building

The equipment in the fuel forwarding building is original equipment. The equipment generally works well. The 2 inch piping between the building and the engines was replaced 2 years ago. The piping was originally buried however due to oil leaks was run above ground when replaced. The above ground piping is not heat traced or insulated. The abandoned underground piping was cleaned and capped.

There is an ongoing fuel oil temperature related problem in the winter months resulting in the engine failing to light off. When the engine does run everything is ok. This problem has occurred since the piping was run above ground. HYDRO is looking into the problem.

3.11 Electrical Equipment

AW reviewed some of the observations and comments on the electrical equipment contained in the Stephenville Interim Report – switchgear, cabling, bus duct, batteries, chargers, relays etc. Since the equipment at Hardwoods is similar, AW will be looking for similar items and an assessment of their condition.

There was little in the way of commentary from HYDRO on the Hardwoods electrical equipment. File searches are underway to uncover any pertinent information on equipment refurbishments, replacements and test information.

3.12 Instrumentation & Controls

JMSP also reviewed some of the observations and comments on the control and instrumentation contained in the Stephenville Report. The DCS system at Hardwoods was also replaced in 1999 with an ELSAG Bailey INFI 90 system. It was noted that not a lot of cabling was replaced at Hardwoods when the INFI 90 system was installed unlike the situation at Stephenville. HYDRO stated that the main cabling junction boxes at Hardwoods in some cases was a bit of a "rat's nest" and should be looked at during the site visit.

JMSP, from discussions with Craig Warren, noted there are unbudgeted plans to replace the vibration monitoring system at Hardwoods. KK reported there is a Bob Stoyles vibration analysis report available on Hardwoods and has been placed on the CD.

JMSP

JMSP queried if there has been an interposing relay problem at Hardwoods as was the case at Stephenville. There was no direct response at the meeting. JMSP to discuss the matter with Craig Warren.

AM stated that Instrumentation spares are listed on the CD.

HYDRO noted that the bearing thermocouple connections at Hardwoods are in rough shape.

**Action By**

4. <u>NG Documentation & Information Requests</u>

AM provided three CD's on information collected since the Stephenville site visit. Along with the CD's AM provided a Summary List outlining the CD content. The CD's include a mix of information on the Stephenville and Hardwoods sites. A copy of the Summary List is in Attachment 1. With reference to the Summary List, the following are several comments on outstanding information as noted at the Meeting:

- Item 1 – A J.D.E. Work Order List has been provided for both sites.
- Item 2 – Curtis Wright Manual for Stephenville included.
- Item 3 – An itemized list of major upgrades to equipment since 1990 has been included.

AM
- Item 4 – No electrical testing information on the CD (Item 4c) for either site. Information to follow. The P&C information on the CD relates to Hardwoods only. Stephenville to follow.

AM
- Item 5 – The Copy of the Operator's Log is for Stephenville only. Information on Hardwoods to follow in 2 weeks.

AM
- Item 6 – A copy of the semi-annual inspections relate to Stephenville only. Hardwoods information to follow.
- Item 7 – Gas Turbine Test Run Forms for the past 5 years have been included for both sites.
- Item 8 – DOE operating certificate for each site included.
- Item 9 – Electrical single line diagram for Stephenville

AM
included. The single line for Hardwoods will be provided later.

AM
- Item 10 – An oil analysis Report for Stephenville has been included. The Report for Hardwoods is in progress and will follow.

- Item 11 – A list of major stocked spare parts applicable to both sites is included.
- Item 12 / 13 -- Copies of the P&C single lines and tripping logic for both sites are included.
- Item 14 – Balance of P&ID's for both sites are included.
- Item 15 – A list of major equipment service suppliers for both sites is included.
- Items 16 / 17 / 18 – Information on instrumentation items outlined in these 3 Items is on the CD

AM

BH queried if any of the requested information, outlined in a NG email of July 24th, relating to electrical testing and visual examination of the alternator and excitation system components has been assembled. AM stated that the email was distributed to various parts of HYDRO for comment/inputs.

**Action By**

5. <u>Operational Data – Hardwoods & Stephenville</u>

In order to carry out the Life Cycle Analysis work on the various Options as required by the HYDRO RFP, NG requires the following operational information from HYDRO for each Site:

AM / NS

- Annual MWhrs last 5 years – HYDRO to provide.
- *Annual forecasted MWhrs next 15 years. [For this item, it was agreed that NG would use the information for the last 5 years on a go forward basis]*

AM / NS

- Synchronous condenser operating hours last 5 years – HYDRO to provide.
- *Annual forecasted synchronous condenser operating hours next 15 years. [For this item, it was also agreed that NG would use the information for the last 5 years on a go forward basis]*

AM / NS

- Number of successful start-stops last 5 years – Engine A / Engine B / Alternator – HYDRO to provide.
- *Number of unsuccessful start-stops last 5 years – Engine A / Engine B / Alternator. [It was agreed that this information would likely be difficult to collect and the item would be dropped].*
- *Forecasted system changes that can impact the operational mode of each Gt. [Again it was agreed for the purposes of the Study that the Gas Turbines would*

*continue to operate in the future as they have in the past regardless of any future system changes].*

**Action By**

6. Financial Data – Hardwoods & Stephenville

AM / NS

In order to carry out the Life Cycle Analysis work on the various Options as required by the HYDRO RFP, NG requires the following financial information from HYDRO for each Site:

- Operations & Maintenance budgets/actual costs for last 5 years – HYDRO to provide.
- An explanation on how overhead costs are allocated between the two sites – HYDRO to provide
- An explanation on how O&M costs are allocated for each of generation and synchronous condenser modes of operations – HYDRO to provide
- Annual projected fuel costs going forward – HYDRO to provide
- HYDRO's cost of money / interest rates for debt & equity / allocation of debt & equity for new capital expenditures / inflation rates going forward – HYDRO to provide
- There was some discussion on whose financial model would be used to do the life cycle cost analysis work. NG can develop a model, however there may be more value in using the HYDRO model used to justify capital work projects, particularly if HYDRO is going to use the Study Report in a submission to its Regulator for capital work on the Gas Turbines. HYDRO to check internally on this matter and will advise.

7. Contract Document Status

The contract document between HYDRO and NG had not been signed as of August 21st. BH noted that two items requested by HYDRO from NG remain outstanding although actions have been taken by NG to provide the information which is from third parties. The two items are (i) registration by NG with the Registry of Companies in NL (Note – the registration certificate was received by NG subsequent to the Meeting and forwarded to HYDRO) and

BH

(ii) registration by NG with the NLCSA Board regarding a Certificate of Recognition. NG is registered with the NSCSA for this purpose.

AM / NS

NG has applied for registration with NLCSA but as of August 21st,

had not received a registration certificate. HYDRO to check internally as to whether registration with NLCSA was necessary for the Gas Turbine Condition Assessment Study.

**Action By**

8. Stephenville Interim Report

HYDRO

BH alluded to the Stephenville Interim Report that was issued to HYDRO on August 17, 2007. NS had an opportunity to briefly review the Report and stated that the content and makeup of the Report was what HYDRO had in mind for the Study. BH welcomed any comments that HYDRO might have on the Report and asked that comments be provided by August 31st.

**Day 1 pm – August 21, 2007**

9. A site visit was made in the afternoon. At the time, Engine A was on Outage; Engine B was available for service and the alternator was in synchronous condenser mode of operation. A fibreoptic borescope inspection was conducted on Engine A. NG personnel, accompanied by HYDRO personnel, reviewed the Gas Turbine equipment and the balance of plant mechanical, civil, electrical, controls and instrumentation equipment. The alternator and exciter were not available for inspection.

When attempting to startup Engine A and engage it with the rotating alternator, both the alternator & Engine A tripped. Indication was that the clutch had not engaged within a prescribed time, resulting in the trip. Following a post mortem conducted by HYDRO it was determined that the clutch had actually engaged, however in doing so, the cover of the clutch proximity switch had been ripped off, while the clutch was engaging, causing the switch to malfunction and send an erroneous signal to the DCS system. There appears to be a physical interference problem with the proximity switch when the clutch engages. HYDRO noted this problem has occurred before on both engines however more frequently on the A end than the B end of the Gas Turbine. HYDRO to do further investigation to determine and correct the cause of the interference.

**Day 2 am & pm – August 22, 2007**

**Action By**

10. The site visit continued on day 2. At the time, Engine B was on Outage; Engine A was available for service and the alternator was in synchronous condenser mode of operation. A fibreoptic borescope inspection was conducted on Engine B. NG personnel, accompanied by HYDRO personnel, continued their review of the Gas Turbine equipment and the balance of plant mechanical, civil,

electrical, controls and instrumentation equipment. The alternator and exciter again were not available for inspection.

**Action By**

11. Other

AM

HYDRO is asked to provide a copy of the following drawings noted during the site visit:

- No. B1-373-E-010 Rev 3 (Excitation System)
- No. A2-1092 Rev 3 (Station Services Schematic)
- No. HWD – 1 Rev 17 (Hardwoods Terminal) - size 81/2" x 11"

**Minutes Prepared By:**
Bill Hearn

# ATTACHMENT 1

# INFORMATION CD – SUMMARY LIST

**Information Request:**

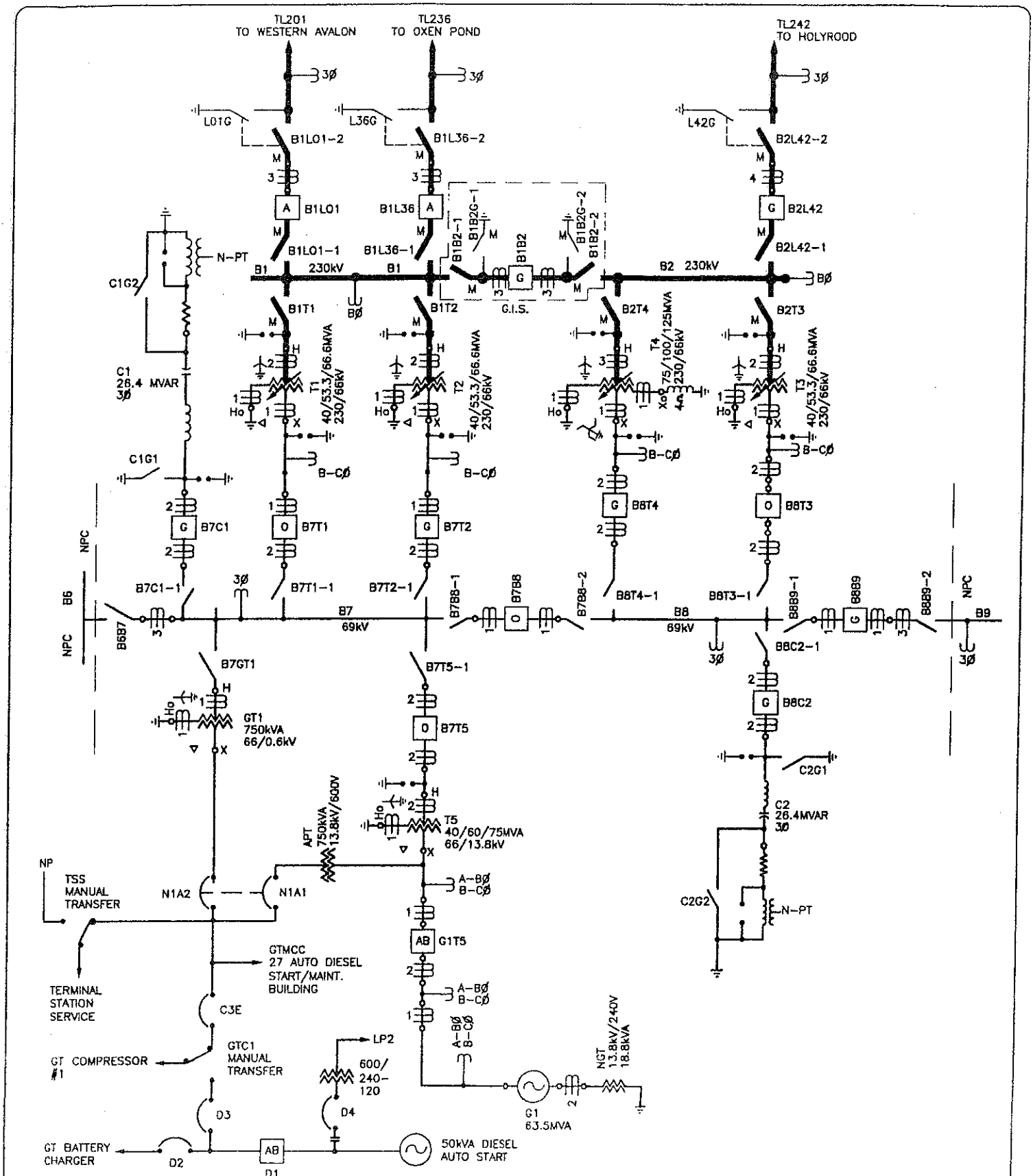
## SVL - HWDS CONDITION ASSESSMENT

| No. | Item | Action |
|---|---|---|
| 1. | J.D.E. Work Order List (all items) – electronic format | J.W. |
| 2. | Copy of Curtis Wright Manual for Stephenville – electronic copy | S.C. |
| 3. | Itemized list of all major upgrades – projects done since 1990 including major equipment replacement: | |
| | (a) Mechanical (G/T overhauls, piping) | N.S. |
| | (b) Civil/Environmental | N.S./T.C. |
| | (c) Electrical | D. Hicks |
| | (d) P&C | C.W./B.W. |
| 4. | Test Equipment Reports over the past ten years: | |
| | (a) Mechanical | N.S. |
| | (b) Civil/Environmental | N.S./T.C. |
| | (c) Electrical (i.e. motors, gen. exciter, switchgear, etc.) | D.H. |
| | (d) P&C | C.W./B.W. |
| 5. | Copy of Operator's Log back to 1992 | S.C./operator |
| 6. | Copy of Semi-Annual Inspections<br>- 21 page document<br>- past 5 years | J.W./S.C.. |
| 7. | Gas Turbine Test Run Forms<br>- past 5 years | J.W./S.C. |
| 8. | G/T Operating Certificate from DOE | N.S. |
| 9. | Electrical drawings – single line diagram | D.H. |
| 10. | Oil Analysis Reports + Glycol (last 5 years) | J.W./S.C. |
| 11. | List of Major Spare Parts in Stock<br>- Mechanical<br>- Electrical<br>- P&C | J.W./S.C. |
| 12. | P&C Single Line Diagram | C.W./B.W. |
| 13. | P&C Tripping Logic Diagram | C.W./B.W. |

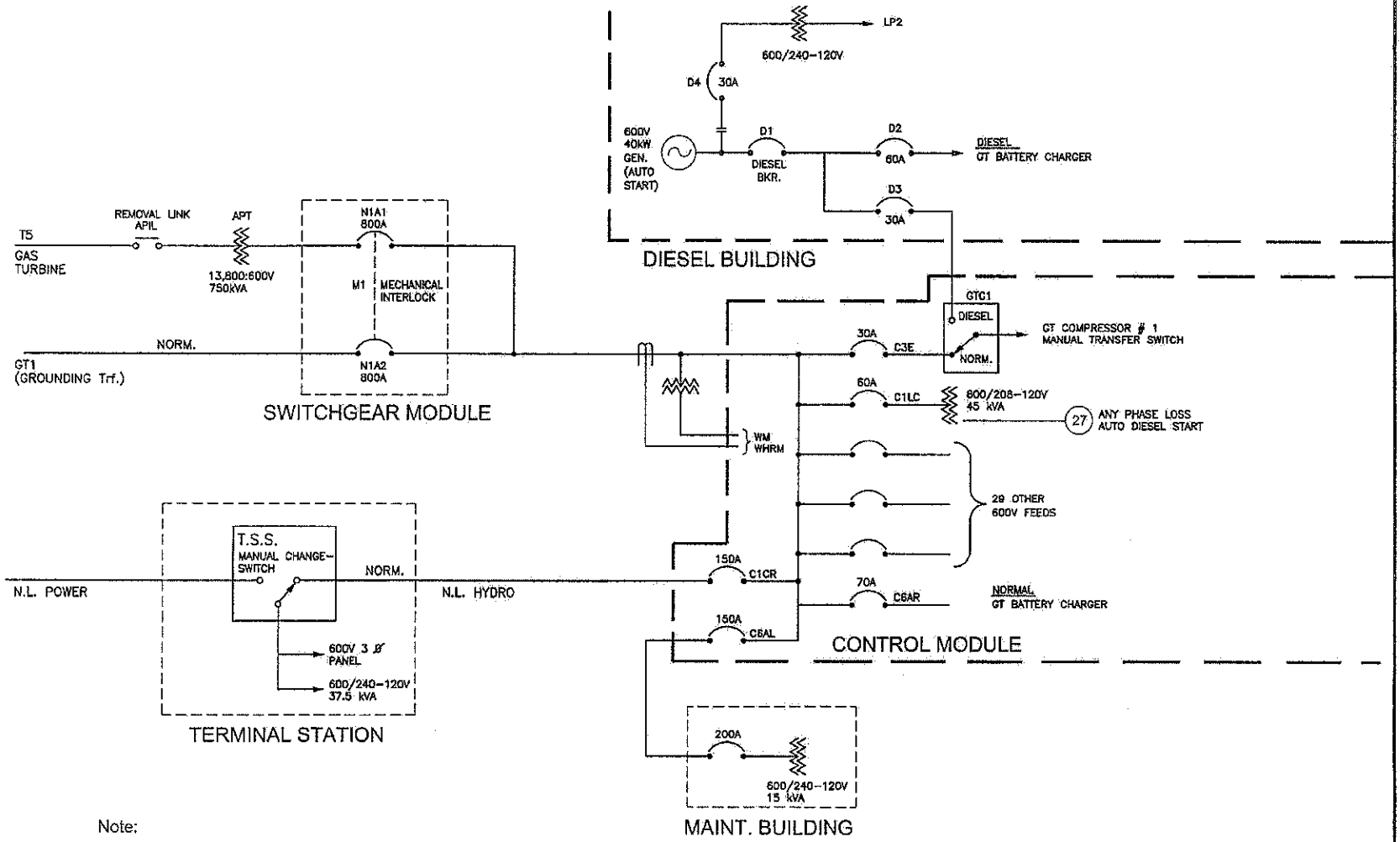
| No. | Item | Action |
|---|---|---|
| 14. | P & Ids<br>- List of IDs? | C.W./B.W. |
| 15. | List of major equipment supplies of past<br>- Mechanical<br>- Electrical<br>- P&C | <br>N.S.<br>D.H.<br>C.W. |
| 16. | ID type and count per system<br>- Which ones have failed? | C.W./B.W. |
| 17. | List of Field Instrumentation Devices<br>* only if readily available | C.W./B.W. |
| 18. | List of known problems and proposed solution, if any (P&C) | C.W./B.W. |
| 19. | Bob Woodman to coordinate a teleconference between Craig Warren and Jean Marc of NG | B.W./C.W. |
| 20. | Prepare a list of major installations/modifications/equipment replacements that have taken place over the years, with brief two or three lines of description for each item and possibly an associated drawing that would have been prepared or a readily available report. This would include large ticket items such as tank farm upgrades and the P&C upgrade done in the late 90's. It is not expected that many such other items have taken place over the years. To prepare this information some of you may have to quiz some of the people in your section who have worked a lot of years at Hydro as this information may not be easy to find from the files and could prove to be a very time consuming exercise. | |
| | (a) Mechanical<br>(b) P&C<br>(c) Electrical | N.S.<br>C.W.<br>K.K/A.O-P. |

# APPENDIX 2
# SINGLE LINE DIAGRAMS
# HARDWOODS AND STEPHENVILLE

# APPENDIX 2
# SINGLE LINE DIAGRAMS
# HARDWOODS AND STEPHENVILLE




| | | | |
|---|---|---|---|
| DRAWN BY: J.T. | REVISED BY: D.R. | NEWFOUNDLAND AND LABRADOR HYDRO | DWG NO HWD-1 |
| APPROVED BY R.S. | | SYSTEM OPERATING DIAGRAM<br>HARDWOODS TERMINAL STATION | REV NO 17 |
| DATE 07/07/19 | | | |




Note:
T.S.S. – TERMINAL STATION SERVICE

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

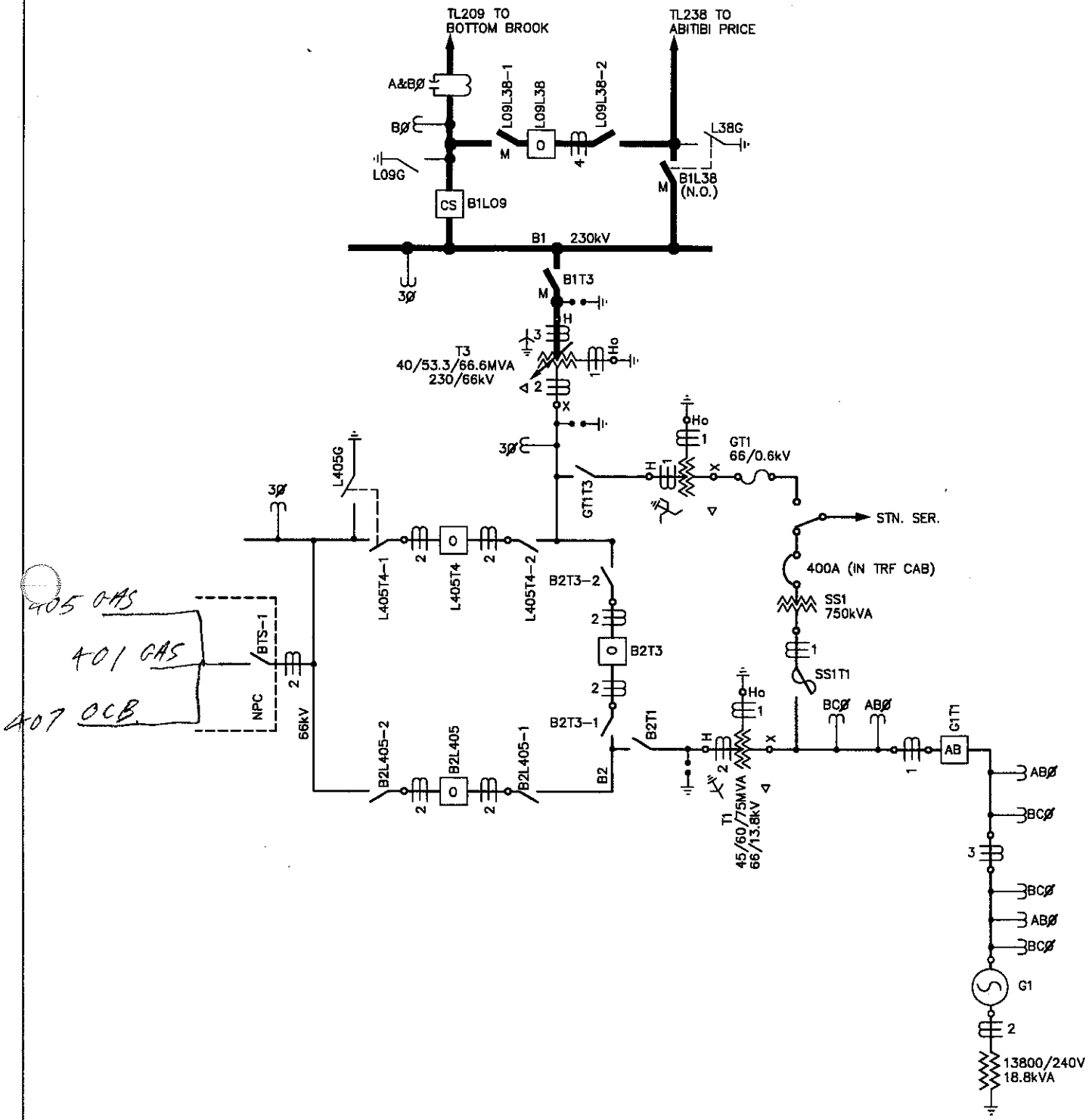
| NO. | DATE | DESCRIPTION | DWN. | DESIGN. | CHK. | APP'D |
|---|---|---|---|---|---|---|
| REVISIONS | | | | | | |

| | |
|---|---|
| ELECT. | SCALE: N.T.S. |
| CIVIL | DESIGNED: |
| TRANS. | DRAWN: D.R. |
| MECH. | DATE: 2008/01/03 |
| P&C | CHECKED: |
| TELC. | APPROVED: |

# HARDWOODS STATION SERVICES SCHEMATIC

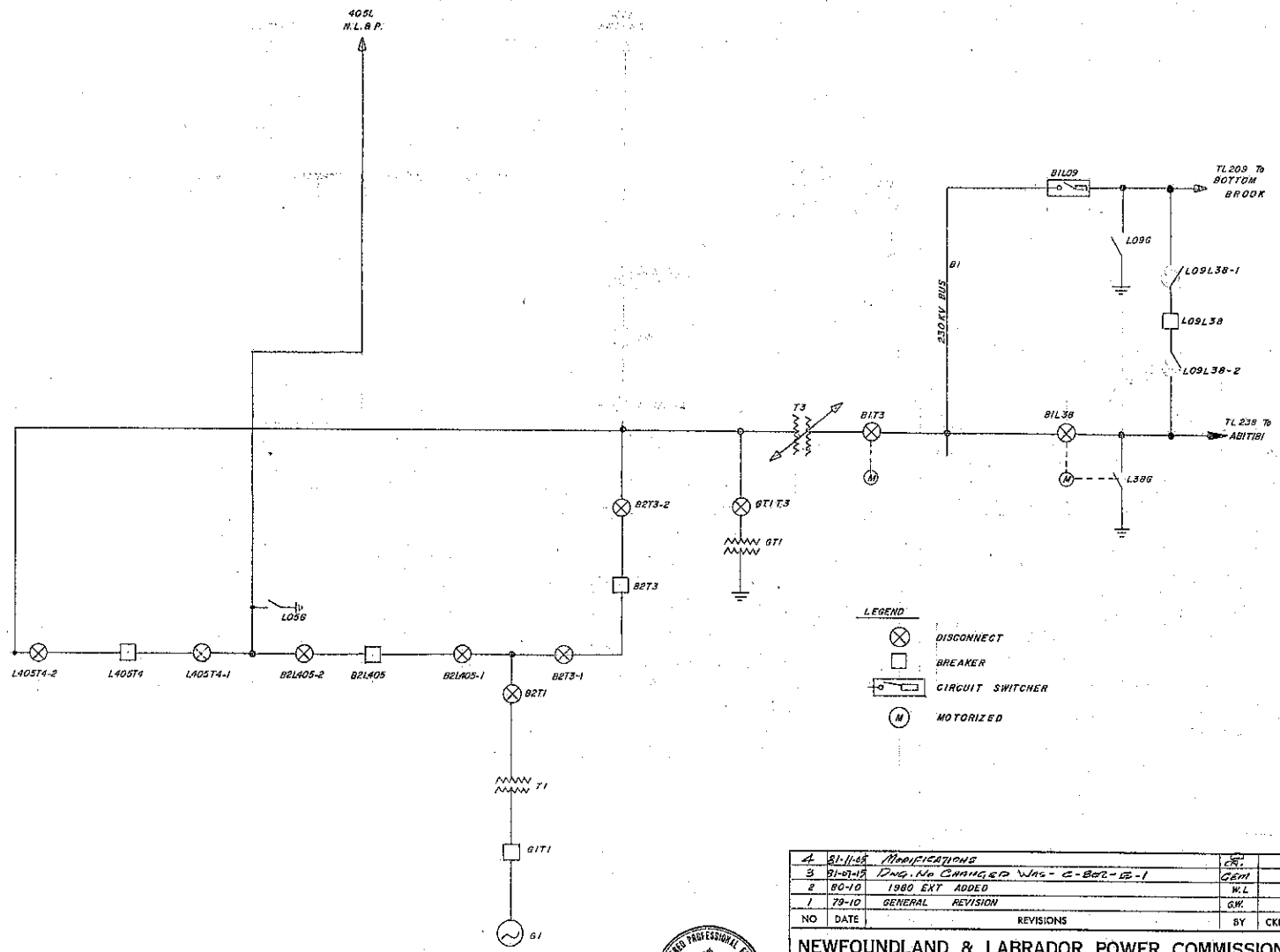
| W.O. NO. | DWG. NO. | REV. |
|---|---|---|
| | A2 - 1092 | 3 |

C.A.D.




| | | | |
|---|---|---|---|
| DRAWN BY D.R. | NEWFOUNDLAND AND LABRADOR HYDRO | | DWG NO SVL-1 |
| APPROVED BY C.Q. | SYSTEM OPERATING DIAGRAM<br>STEPHENVILLE TERMINAL STATION | | REV NO 10 |
| DATE 2006/11/22 | | | |

319-E-1




| NO | DATE | REVISIONS | BY | CKD. |
|---|---|---|---|---|
| 4 | 81-11-05 | MODIFICATIONS | | |
| 3 | 81-07-17 | DWG. No CHANGED WAS: C-B01-E-1 | GEM | |
| 2 | 80-10 | 1980 EXT ADDED | W.L | |
| 1 | 79-10 | GENERAL REVISION | G.W. | |

NEWFOUNDLAND & LABRADOR POWER COMMISSION
ST. JOHN'S, NEWFOUNDLAND

# STEPHENVILLE TERMINAL STATION
## SINGLE LINE DIAGRAM

REGISTERED PROFESSIONAL ENGINEER
L. G. STURGE
SIGNATURE
PROVINCE OF NEWFOUNDLAND

| Reference Dwgs. | DWG. NO | TITLE | APPROVAL |
|---|---|---|---|
| | | | |

| | | |
|---|---|---|
| SCALE N.T.S. | DESIGNED BY | DRAWN BY J.G. |
| CHECKED BY | APPROVED BY MS | DATE AUG. 16 '74 |
| PROJECT NO. | SHEET ..... OF ..... | DWG. No C-319-E-1 |

# APPENDIX 3
# HYDRO JD EDWARDS MAINTENANCE ACTIVITIES PRINTOUT
# HARDWOODS AND STEPHENVILLE

# APPENDIX 3
# HYDRO JD EDWARDS MAINTENANCE ACTIVITIES PRINTOUT HARDWOODS AND STEPHENVILLE

## Hearn, Bill G.

**From:** NSeymour@nlh.nl.ca
**Sent:** Friday, July 13, 2007 2:29 PM
**To:** Hearn, Bill G.
**Cc:** JWheeler@nlh.nl.ca
**Subject:** NLH Gas Tubine Assessment

**Attachments:** SVL GT History.xls; HWD GT History Rev 1.xls; GASTURBINE2006 002.jpg; GASTURBINE2006 001.jpg


SVL GT History.xls (51 KB)


HWD GT History Rev 1.xls (144 ...


GASTURBINE2006 002.jpg (705 KB...


GASTURBINE2006 001.jpg (706 KB...

Bill,

Attached are lists of items, briefly described, summarizing operating problems we have experienced over the past 10 years. These were extracted from a much larger list that records all maintenance actions. In addition, the diary text below highlights some of the particularly troublesome incidents as noted by Jim Wheeler.

Nelson
----- Forwarded by Nelson Seymour/NLHydro on 07/13/2007 02:43 PM -----

James Wheeler/NLHydro
07/03/2007 04:03 PM

To: Hughie Ireland/NLHydro@NLHydro
cc: Nelson Seymour/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject: Re: Update of History at SVL and HWDGT(Document link: Nelson Seymour)

Have attached the up to date log I have been keeping for HWD and SVL combined. Please find the stored testing and trend data on the X: drive as follows X;\Gas Turbine Trending (SVL-HWD). This is what has been scanned and stored to date.

Regards
Jim

(See attached file: SVL GT History.xls)(See attached file: HWD GT History Rev 1.xls)

2006-01-04
HWD GT Fuel transferred from Hydro Place to HWD (21,418 liters). arranged by Norman Bungay. Transferred by Crosby's Industrial using the same truck as is used to empty the sump at HWD.

2006-01-23
Due to system load requirements HWD and SVL GT's were required for generation.

0702 hrs HWD GGB was started in Generate mode. At that time GGA failed to start.

0706 hrs SVL GGA failed to sync after 2 attempts.

0755 hrs HWD GGA was started from local control and put on line. Both units were on line at this point with approximately 30 MW load total.

0901 hrs SVL GGA put on line and loaded to approximately 20 MW. Maximum available due to EGT Spread alarm. The unit was monitored locally and kept at 20 MW .

1048 hrs HWD Unit tripped with approximately 28 MW. Investigation indicated the DC breaker for unit controls (both GGA & GGB) tripped. DC breaker was reset and unit (GGA & GGB) given a start command. Breaker tripped again during the attempt to start. In local control GGA only was given a start command resulting in the breaker again tripping. GGB alone was then given a start command and started successfully. It was determined that the DC fault was directly linked to the operation of GGA. GGB was then loaded to 17 MW to support system load. At that time technicians at site were investigating the problem with GGA.

1359 hrs HWD GT tripped (GGB) with at 17 MW / 17 MVAR due to anti ice fail. Crew on site removed anti ice valve and solenoid from GGA and replaced the failed unit on GGB with it. Unit was made available at 1658 hrs. At that time the anti ice unit was removed from GGB at SVL and shipped via air to St. John's to arrive at 2100 hrs.

1658 hrs HWD GGB put on line and loaded to 15 MW. Restricted to 15 MW due to EGT Spread alarms.

2148 hrs HWD GT was switched to Sync Condense Mode as per system requirements. During this time the anti ice unit from SVL was installed on HWD GGA and trouble shooting of the DC cct. continued.

2208 hrs HWD tripped at 0 MW / 0 MVAR while attempting to switch GGA to generate.mode. DC breaker trip. Further trouble shooting at that point identified a failed cable in the DC control cct. The cable was replaced and a GGA start was again attempted. The DC breaker did not trip at this point but attempts to start GGA were unsuccessful due to GGA Incomplete Sequence. Several attempts were made to start GGA and at approximately 0245 hrs crews discontinued work. HWD was left with GGA unavailable and GGB available up to the 15 MW restriction.

2006-01-24
0208 hrs HWD GGB on line.

0216 hrs HWD switched to sync condense mode.

1015 hrs SVL GGA sustained a controlled shutdown at approximately 5 MW due to EGT spread deviation. At that time ECC gave GGA a remote start command and set load to 15 MW. In ramping to 15 MW the trip (controlled runback) occurred.

1026 hrs SVL GGA. In local control the operator started GGA and kept the unit at min load (2 MW) for 10 minutes to let the machine stabilize while monitoring EGT. After 10 minutes to EGT was stable at 65 deg. C and he loaded to unit to 5 MW as required by ECC.

1200 hrs Crew returned to HWD to further troubleshoot the problems with GGA incomplete sequence. They indicate the incomplete sequence problem appears to be associated with the cable issue from last night and a complete unit outage is required to further investigate. An outage is scheduled for 2006-01-24 (2100 hrs) to continue investigating.

2006-01-24 HWD GGA DC breaker trip was identified as failure of the snubber circuit for the fuel solenoid. Zenor diodes across 401 and 4 (fuel solenoid) was shorted causing the DC breaker to trip during the starting sequence. The snubber was removed and unit returned to service without the snubber. Currently working with P&C and engineering to identify replacement parts.

2006-01-30 to 2006-02-03
SVL GGB Combustor cans were removed from GGB and replaced by a refurnished set stored in HWD. Rolls Royce representative Alain Joseph was on site for this. There were no apparent defects identified with the removed cans other than some erosion near the interconnector port on #2. Alain indicated this would not create the EGT problems we are experiencing. There were design differences in the cans. The manufacturer indicated the cans from HWD were Phase 1 and the existing cans on GGB were phase 2. Phase 2 is a upgrade to increase the time between maintenance overhauls. The manufacturer indicated putting back phase 1 cans is not a problem.

2006-02-05 2329hrs. SVL GGA failed to start (3 attempts) due to exhaust spread. Ray Rowe made serval adjustment to the fuel transducer however no luck. At present unit is unavailable for system.

2006-02-07 & 08
SVL GGA logic was modified to inhibit EGT Spread Deviation shutdown anf trip until the engine reaches N3 speed greater than 3540rpm (clutch engaged) and generator is at minimum load (2 mW). EGT spread deviation alarm will be enabled during startup but shutdown (runback) and trip are disabled. Also at that time the screen graphics was modified to show EGT Spread Deviation on both GGA and GGB. GGA was test run to 25 mW successfully.
A work order is in place to make the same logic changes to SVL GGB an HWD GGA and GGB.
HWD GGA & GGB logic changes are scheduled for the week of Feb. 13, 2006.

2006-02-08
SVL GGB burners. Rolls Wood reported SVL GGB burners have been inspected and 4 of the 8 require extra repairs. Revised quote for the inspection and reconditioning of these burners is 17,519.66 British Pounds.

2006-01-15
HWD GT The upper bearing on Fan # 2 in the glycol cooler was identified as being noisy. Bearing detail was identified and a replacement is being shipped to be installed 2006-02-18 & 19 (Sat & Sun) due to the availability requirements of the gas turbine. On 2005-05-05 the lower bearings on the same fan were found noisy and both lower bearings were replaced. Provision is made to replace the upper bearing on Fan # 1 as soon as the work can be scheduled.

2006-02-20
HWD GT tripped at 9 MW during testing to determine if the glycol cooler could maintain enough cooling to the unit with #2 fan turned OFF. Unit tripped on Low Liquid Fuel Pressure. Problem was investigated and it was determined the motor operated fuel valve had malfunctioned. It appeared to have overtravelled leaving no indication to the DCS system whether the valve was open or closed. Valve was operated several time and operated correctly. Unit was returned to service. One possible reason is the valve bay have been iced outside and when the ice broke free it overtravelled due to excess torque being applied.

2006-02-23
SVL GGA experienced a EGT spread deviation shutdown at 1128:44 hrs on Feb. 23 during startup and loading for generation requirements. Craig Warren and P&C West are investigating the trend logs to determine the cause of runback as the EGT spread deviation indicated 53 deg C was reached and shutdown occurs at 60 deg C.

2006-02-24
HWD GT Inverter failed. Inverter bypassed to station service AC until outage can be apptoved to replace.

2006-02-24
HWD GGA. Unable to load GGA beyond 5 MW with a fuel valve position of 48 % which should represent half of full losad (approximately 12 MW).
All three fuel filters on GGA replaced without success.
Jordan valve removed and calibrated at Diesel Injection without success.
During testing it was identified that one of the igniters on GGA was not working. Igniter was replaced.

2006-02-25
HWD GGA tested for load capacity and was only able to achieve 8.8 MW at 100% fuel valve. Fuel restriction still an issue. During shutdown and transfer to sync condense the clutch on GGA failed to release. The clutch casing had to be removed and the clutch physically separated. GGA will not be available for service in any capacity until the clutch is removed and repaired. During the emmediate requirement to restore HWD sync condense it was identified that when GGB was started, the motorized main fuel valve did not open.

2006-03-06
HWD GGB. Old burners removed and replaced with overhauled burners taken from SVL GGB. Unit was run up and went into alarm (EGT Spread Deviation) at 18 MW. Unit released with same 15 mw load restriction until further notice.

2006-03-13
HWD GGB. Engine fuel hoses inspected and found okay. Hoses were exchanged with GGA as well with no success to correct the EGT spread deviation problem on GGB.

2006-03-14
HWD GGA. Total outage today to do the following.
1) Oil solenoid on GGA clutch replaced. A oil line to the solenoid was identified as damaged and replaced also.
2) Inverter at Gas turbine replaced.
3) Anti ice valve replaced on GGA with rebuilt that was removed Jan 23, 2006.
4) Failed cable to fuel forwarding module replaced.
During start up problems were experienced with the supply breaker to the glycol pump tripping. Another breaker (not sized exactly as the failed one) was used to replace the failed unit. A new breaker sized the same as the original is being sourced. New breaker on order.
The repaired anti-ice valve failed to operate and showed the same problems as when it failed originally , 2006-01-23. It was removed and replaced with the unit drom SVL GGA. Failed unit sent back to Ozark for re-evaluation.
GGA was started and run to 1300 rpm at which time a fuel leak was detected on the fuel line to engine. On rundown it was not determined definitely if the clutch operated correctly. Both engine and generator were coasting at the same time. GGA clutch was dissengaged when GGB was started to put the unit on in sync condense.

2006-03-15
HWD GGA.
Failed anti-ice valve returned to Ozark for evaluation. Crew repaired leaks on GGA fuel lines.
Ran up GGA and tested manual valve in fuel return line. Testing indicated

this bypass circuit is not our problem.
Next step is to replace GGA fuel actuator to identify GGA not able to get to full load.
On unit stop (GGA) today the clutch failed to separate!!!!!

2006-03-16
HWD GGA.
Clutch solenoid valve sent to Diesel Injection for inspection.
To determine the loading issues with GGA, the manufacturer suggests replacing the fuel distributor. We have a spare distributor at HWD.
Mechanics installed today a fuel pressure gauge to monitor the fuel pressure into the distributor.
The mechanics installed a pressure gauge on the input line to the fuel distributor on GGA today and ran the unit to 8 MW. Pressure @ 8 MW and full valve was recorded at 800 psi.
Can you confirm if this pressure is what would be expected.
HWD sump was pumped out today.

2006-03-17
HWD. Nelson discussed with Rolls Wood. RR indicated the distributor is most likely not the issue with GGA fuel and loading. They referred to a servo dump valve as as possible suspect and Nelson will persue details with RR today to determine a test procedure or process to investigate the servo dump valve.
RR indicated the distributor is considered a prime suspect for the EGT spread seviation issuses with GGB and recommends replacing it on GGB.
Plan for today is to replace the distributor and final filter on GGB and test the unit.
Nelson will also check on the status of the anti-ice valve at Ozark as well as the clutch solenoid at Diesel Injection.
Also Reg suggested installing a pressure gauge on on of the output lise from the distributor. Is this a good idea and if so what should we expect to see. Are we wasting our time here and should we go directly to replacing the distributor.
By the way the clutch on GGA failed again on run down.
Fuel distributor replaced on GGB as well as final filter and unit test run to 18 mW at which time the EGT spread deviation became active again.
Changing the distributor on GGB did not correct the problem on GGA.

2006-03-18
HWD GT
High sump alarm recieved from HWD. Investigation found sump full. Also a local alarm indicating main lube oil level low. Found sump full of lube oil. Sump was emptied, unit shutdown and investigation started to identify the source of oil leak.

2006-03-19
HWD GT
Oil leak was found to be the expansion joint to the rear journal bearing on turbine A. Repairs were made and 6 drums of oil required to replace that lost from the main lube oil tank.

2006-03-20
HWD GT
Oil sourced from HRD plant and process to top up tank today. 10 barrels ordered from HRD.
Mechanics are checking the remaining expansion joints in the lube oil system today for possible leaks and integerity.
The events of Saturday indicated the lube oil level low alarm is not seen by the ECC. This low level alarm inhibits the oil heaters from coming on thus blocking a unit start.

Wayne's note on Weekend findings:
Guess you know by know we had high sump alarm over the weekend.
Sump was pumped out Thursday and again on Saturday.
The only indication ECC had was high sump alarm.
On site there was also a lube oil level low alarm.

ECC did not have any indication of this alarm.
It was only after we shut the unit down (take off sync cond) did we loose the green lights.
ECC should have this alarm and it should be called MLO level low alarm.
Most all the oil that was loss was collected in sump.
ECC keeps getting high temp alarm on the bearings and Gen alarm.
On site we have MLO tank temp low alarm, the heaters will not cut in, with a low level
oil alarm, you don't want the heaters on, in case they are out of oil.
These alarms needs to be straightened out asap.

There was an oil leak on the expansion joint to the rear journal bearing on turbine A.
We need six drums of tresso 32 oil.
We need a work order to cover work done this weekend.

Note to Hughie to request full review of inputs to DCS to determine adequacy of alarm functions and inhibits especially to ECC.

2006-03-21
HWD GT
More lube oil Teresso 32 required to bring the reservoir up to full mark.
Another 13 barrels ordered from HRD and system filled today.
The clutch solenoids on GGA and GGB to be switched today with the intent to confirm the failure mode of GGA clutch. Flex lines to both solenoids will be replaced as recommended my mechanic.
Repairs to demister scheduled for today.
Complete inspection of oil line flex connections today and tomorrow.
Note to Steve to discuss PM checks to include inspection of lube oil flex connections as well as ckecks of lube oil level at both HWD and SVL.
Clutch solenoids were interchanged on GGA and GGB. Both GGA and GGB were run up. GGB functioned correctly and GGA clutch failed the same as prior to changing the solenoid. (No improvements to GGA clutch problem)
During the run of af GGB the intermediate filter housing o-ring failed causing a fuel leak. O-ring was replaced.
Sump high level alarm was modified to be indicated at both ECC and local. Before this only the ECC received the sump high level alarm.

2006-03-22
HWD GT
P & C to perform checks today to confirm the controls to GGA clutch solenoid are working correctly. Monitor solenoid voltage during run-up and shutdown.
P & C found fuse blown in the clutch solenoid cct preventing the solenoid from operating. This is a output from the DCS. Blown fuse was a result of a failed snubber. This snubber is located in the same jct box as the one that failed 2006-01-23 in the liquid fuel valve cct.
Snubber was removed and the unit returned to service. This cct does not have nlown fuse indication. Snubber removed and fuse replaced. GGA clutch tested for operation and is now functioning correctly.

2006-03-23
HWD GT
Checked DC controls to fuel system on GGA and found a failed snubber on Dump Servo Valve SV-LF-1. Snubber removed and unit tested to normal load (24.8mw) without alarm. HWD GGA back to normal nonrestricted operation.
Anti-ice valve will be tested on GGA at the first opertunity and if okay SVL GGB anti-ice will be returned to SVL.

2006-03-24
HWD GT
GGB Nelson recommending swap burners 1 (hottest) and burner 4 (coldest) and test run monitoring temps. and alarms. Targetted for today to identify GGB spread deviation issues.
Old burners from HWD GGB are being transported today to be installed on SVL GGB.

Still waiting on anti-ice testing at HWD before getting anti-ice back to SVL GGB.

Results as follows:
Reg interchanged burners 1 & 4. No change, got exhaust spread alarm at 19 MW.
No 1 burner the coldest at 626
No 2 burner 654
No 3 burner 690
No 4 burner the hottest at 708
No 5 burner at 670
No 6 burner at 689
No 7 burner at 685
No 8 burner at 675
Exhaust average 674
B temp reference 766
Alarm spread comes in at 50

Also fuel flex hoses on burners 1 and 4 (GGB) were switched withsame on GGA.

Interchanging the flex hoses and swaping burners had no change to GGB EGT Spread Deviation.

2006-04-07
SVL GGB (Hughie's Note)
Ron Mercer adjusted fuel transducer to be camp. with our new cans that' fitted with the old burners from Hardwoods.We had a couple off failed starts getting the proper setting.
15:30 hrs 5 MW
15:33 hrs 10 MW
15:36 hrs 15MW
15:39 hrs 20 MW
15:42 hrs. 24 MW (UNIT BEING CONTROL BY TEMPERATURE LIMIT)
The spread didn't exceed 25 degrees,when we were at 24 mw it was 22 degrees.

This is a quick note to inform you that Stephenville Gas Turbine End B was tested today, after installing the burners from Hardwoods (GGB), and the unit reached full capacity without any exhaust gas temperature problems. Our next step is to have a discussion with Nelson on Monday to develop a plan of attach for Hardwoods. From this experience it appears the combustion cans in Stephenville were suspect as the spare combustion cans from Hardwoods were installed at Stephenville when the burners (that are now in Hardwoods) were removed and sent to Aberdean for refurbishment.

2006-04-17
Work plan for this week to include replacing of last glycol cooler fan bearing. Top bearing on fan # 1.

2006-04-19
HWD GT
Swapped burners 2 & 5. on GGB. No change, still got exhaust spread temp alarm at 19 MW. I have temperatures and load readings at 5 MW intervals, which I will deliver to N. Seymour tomorrow. Engineering requested to make arrangements with the manufacturer to be on site to oversee the removal of cans from SVL GGB and install same in HWD GGB. This is required to prove if HWD GGB is a cans issue before major investment to fix HWD GGB cans.

2006-04-21
HWD GT
Pressure tested pipeline going to sump, by capping off line in sump and filling line with water, from drain in floor in fuel forward pump house. Checked pipe and 1/2 hour later, no sign of any water. This is the new pipe line that was installed less than a year ago. This test is a result of

the sump being filled with water at a higher rate than previously recorded. Request to engineering for recommendations.

2006-04-07
It was identified that an excessive amount of water is being collected in the HWD GT sump system. Leak test indicates there is a failure in the underground piping. On 2006-07-04 the piping was exposed near End A and a break was found in the pipe joint. Both sections of pipe were tested from the broken exposed area and found the okay except for a failed backflow valve from End A air intake module. Valve was replaced and repairs made to the ruptured joint that was exposed. Work order in place to test system in November, 2006 and spring of 2007.

2006-07-03
GGA failed to start due to a failed proximity switch on GGA clutch. Switch was replaced and unit made available on Tuesday, July 4.

2006-07-16
Note of plan from Hughie to Rob Cater.
In an effort to bring both Hardwoods and Stephenville up to their full 50 MW rating we plan to remove the combustor cans from Stephenville End B (these are the cans that were installed at S'Ville End B and improved the rating from 10 MW to 25 MW) during the week of Aug 7, 2006 and then reinstall the old cans. This will de-rate the unit at S'Ville to 10 MW but will ensure both ends are available for starting for synchronous condenser purposes.

The cans removed from S'Ville will then be transported by road on Aug 14, 2006 and installed in HWD End B. During the same outage to remove the cans at Hardwoods we are also doing an inspection of the LP Turbine blades as recommended in a service bulletin. It is important to note all work at Hardwoods will be under the Supervision and direction of Rolls Royce representative . At the end of this work it is hoped we will have a good idea of the condition of the LP Turbine blades and (hopefully) have HWD End B back to a 25 MW rating (up from the current 15 MW rating).

If everything above goes as planned we will then have to make a decision on sending the combustion cans that come out of HWD End B back for refurbishment (estimated at a cost of ~$300 k) and bring S'Ville End B back to it full rating.

2006-07-26
Reported by Wayne Snow.
Just faxed a work request to Steve, to replace the seals on MLO pump 1. Pump 2 is in service for now. A complete outage is required to remove pump,
(a good time maybe Aug 1, outage) since the complete unit must be down. The pump is normally taken out, brought over to the shop and serviced. We use a blank cover to replace where pump is too, so we can use unit while repairs are being made. Then we will need another outage to re-install
pump. Mechanic required.

2006-08-04
During a run up this past week on Hardwoods End A , we experienced a problem with the anti-ice control circuit that initiated a trip on the unit. After some testing we cannot seem to duplicate the problem. However we have concern with the anti-ice valve on end A and suspect this is the root cause of the problem. Our next step is to remove the anti-ice valve from End B in Stephenville on Tuesday (August 8, 2006) and ship it via air to St.John's to be installed and tested at Hardwoods on Wednesday August 9,

2006.

As a result, End A at Hardwoods shall be restricted from being operated in generate mode but can still be used to place the unit in synchronous condense mode as required. Also for your information Stephenville is fully available up to and including August 7, 2005 (at which time End B will be taken off line for combustion can removal) but Hardwoods is restricted to 15 MW on End B only.

If you have any questions regrading the Gas Turbine over this coming weekend please contact myself at 486-0350 or Jim Wheeler at 486-1042

Installation of valve from SVL delayed until 2006-08-11 as per ECC request. Outage changed.

2006-08-11
Anti-ice valve replaced today with unit from SVL GGB and works properly without alarming.
Testing don on valve from SVL GGB as well as failed valve from HWD GGA. Test detail is recorded on work order 533666 and it was concluded the limit switches embedded in the valve motor are not operating correctly causing the motor to want to run. This is pulling the 24 Vdc power supply down causing false indication to the DCS system which makes both GGA and GGB not available. The valve removed from HWD GGA has ben repaired locally as well as being sent to the UK some years ago for repair. We are unable to make repairs to the valve limit switches.

2006-08-14
Scheduled outage to HWD GGB to perform low pressure turbine inspection and replace combustor cans with those (new / refurbished) that were installed in SVL GGB and proven to get SVL GGB to full load without EGT Spread alarm. Schedule was delayed as it was identified on Monday that the engine (HWD GGB) had to be removed for LP inspection. At that point it was discovered the lifting beam for such was at SVL and had to be transported to HWD. There was no actual delay as the engine had to be readied as well as an extension beam had to be installed prior to the lift. The extension beam had to be modified as to accomodate the mounting bolts even though it was used previously. LP turbine inspection was completed by Steve Press of Rolls Royce (from UK) at 1530 hrs on 2006-06-16, (Wed). Engine GGB was reinstalled and the combustor cans replaced with the set removed from SVL GGB. Significant work was involved from Wed 92006-08-16) to Monday (2006-08- 21) to return the engine and replace cans. Dowels in the engine shroud were very difficult to remove and some were damaged during removal. HWD was test run Monday afternoon (2006-08-21) and results are as follows:
HWD GGB - Before cans changed out reached 19 MW before EGT Spread Alarm.
HWD GGB - Test run after cans changed an EGT Spread alarmed at 22 MW.
Outdide ambient temp at that time was 22 deg C.
HWD GGA was also run at that time and maximum output at that time was 22.3 MW at which point the unit went into high temperature control.
Alain Joseph of Rolls Royce (Canada) was on site for changeout of combustion cans. Due to a death in the family he was unable to stay for the run up.

2006-08-16
SVL GGA
Failed to start on 2006-08-16 and below are the investigation results.

(See attached file: GASTURBINE2006 002.jpg)(See attached file: GASTURBINE2006 001.jpg)

Jim:

Ron Mercer came across a relay burnt out at STVL GT , last week. It is the relay that sends power to the fuel re-circ. valve.
He also found fuses blown in the card that powers this valve, ( both ends

).
After much discussion, it now appears that we have a wrong application of this relay here.

The relay is a miniature ( Micro-electronic MZH A 001 48 10 )
It has a 24V coil , and contacts rated for 10A @ 250 Vac.
From literature obtained on this relay we see that at 125Vdc, it should be interrupting no more than 300mA, and in fact the manufacturer says its relay is not designed to switch DC current/voltage.
We are interrupting at least 3A inductive with this relay and as a result have burnt a hole in it. ( welded contacts ).

Ron is in the process of wiring in interposing relays ( Potter Brumfield KUEP-11D15-110 ) which have contacts rated at 3A @ 150Vdc, and we will have to
obtain some relays to replace those burnt up.

The issue is that upon searching the Dwgs. / Cards etc.... he has found at least eight more solenoids that are running their power through
these same type relays and again these appear to be not rated to carry / interrupt this load. ( Fuel Control and Starter Control )
There may be other circuits undiscovered.

This appears to be designed this way, from Bailey, I assume. It seems that some circuits got interposing relays and some didn't.
I would imagine that at HWD GT we have a similar situation.
There was also a question raised as to whether the Agastats we are using are rated for DC interruption.

I think Engineering should look at this with regard to obtaining a suitable interposing relay , if that is the solution, and what other circuits here are this way.
We will also need mounting gear , wire , din rail,bases, etc....

I think it is probably just a matter of time before other relays on these cards are burnt resulting in more problems.

Clif Quinton.

2006-08-24
HWD GGB
Plan for next week is to install the burners / nozzels that are / were in SVL GGB in HWD GGB and unit will be test run with refurbished cans from SVL GGB along with existing burners from SVL GGB. This combination of burners and cans worked in SVL GGB to get full load on SVL GGB. The cans removed from HWD GGB last week will be installed in SVL GGB and depending on the results of HWD GGB a set of burners will be shipped to SVL GGB.

2006-08-24
Work plan for next week. HWD and SVL
Please proceed with the following plan to investigate EGT Spread problems at HWD GGB and SVL GGB.
1) Combustor cans were removed from SVL GGB (overhauled ones) and installed in HWD GGB last week.
2) Overhauled burners are now in HWD GGB.
3) Install burners that were removed from SVL GGB in HWD GGB. These burners were sent to HWD along with the cans that were removed fron SVL GGB recently. This will then give the same burner / can combination in HWD GGB as was in SVL GGB that allowed SVL GGB to achieve full load without alarm.
4) Test HWD GGB for maximum load.
5) Ship cans that were removed from HWD GGB to SVL and install in SVL GGB.
6) When the results of HWD GGB are know a decision on the next move will be made.
Please schedule the work for HWD and SVL so HWD can be tested and the cans will be install in SVL GGB waiting the burners from HWD (which set to be

determined.
Thanks
Jim

2006-09-21
Note from Nelson On HWD GT MLO Temp trip.
I understand that the controller for the temperature regulating valve was replaced yesterday and that the engine was ran up to 6 MW with normal temps. Avg exh. gas temps are over 200 C higher above 20 MW. I suggest we do a test run to full load to ensure there are no further problems.

2006-09-22
Note from mechanic (Mike Penny) on resolution of HWD MLO temperature problem.
The glycol system seems to be working OK now.
We had 44 MW on unit. The MLO temperatures were
150 & 120. The glycol was 95 & 105.
We took apart the regulator on the glycol system, replaced O-ring, cleaned seats, made several adjustments.
We took apart the Y strainer and cleaned. Checked heat exchanger on the oil system, Had to remove a drum & 1/2 Glycol and replaced some, glycol due to dirt in glycol.
The unit is passed back to ECC, there are a few minor leaks we have to look at, then we are out of here.

Mike

2006-09-29
Prior to the runup of SVL GGB a new / overhauled anti-ice valve was installed. The valve was acquired from Alba Power and the failed unit (originally from HWD GGA) was sent returned to Alba Power as a rebate on the unit we installed in SVL GGB.
This past week the combustor cans and burners were installed on SVL GGB and as a result of today's test run new load availability have been achieved.
The following reflects the present availability of both HWD and SVL GT's.

Hardwoods: ( No change from last update)

END A - 25 MW
END B - 21 MW

Combined with END A and END B running at the same time : 42 MW (This is not the sum of both ends but 2 x the lowest capability)

Stephenville:

End A - 25 MW
End B - 22 MW

Combined with END A and END B running at the same time : 44 MW (This is not the sum of both ends but 2 x the lowest capability)

2006-10-19
A schedule and test procedure has is in place to perform monthly run up testing of the units at both HWD and SVL starting October 25 at SVL and November 8 at HWD. This will exercize the units and verify their operation as will identify equipment failures and enable repairs to be made in a scheduled manner.

2006-10-20
SVL GT
Just a quick note to let you know that GGA was released to the system @13:33hrs,we did a run to light-off to check
the newly installed starter air regulator-everything went well.

Hartery
Also the RTV coating and general painting / repairs were completed as of 2006-10-20.

2006-11-11
HWD GT returned to service after two week outage to complete the following work.
1) Replace AVR with ABB on site for commissioning and in-service checks.
2) Glycol cooler housing replaced by M & M Engineering. Work completed with final painting outstanding due to time restraints. New work was primed only. Final painting to be rescheduled in 2007.
3) Exhaust stack repairs to insulators completed by Black & MacDonald. Inspection of stacks prior to repairs indicated further deterioration from previous inspection in August 2006.
4) Main lube oil pipe and strainer replaced.

2006-11-15
HWD GGA & GGB Deflector Rings
Daily inspection identified the deflector ring on GGB had become displaced and was expelled from the unit through the exhaust stack. Ring was replaced on 2006-11-16 and GGB made available at 2130hrs on 2006-11-16.
On 2006-11-16 operator also found displaced deflector ring on the ground and is suspected to be from GGA. Replacement ring was shipped from SVL for GGA. New rings ordered as the spares are all used.
Outage scheduled for GGA to replace deflector ring on 2006-11-16 but was cancelled due to windmilling on GGA. as the unit was on in sync condense mode. GGB was also windmilling at the same time. Requested complete outage on unit to enable work on GGA. Outage delayed due to problems at HRD.
GGA lower deflector ring was replaced on 2006-11-18 and and bolts were tapped and retorqued on upper ring on 2006-11-19. GGA upper ring would have failed if retorquing had not been done.

2006-11-22
HWD GT GGA Exhaust Stack Cracks
Inspection identified cracks in the exhaust stacks on GGA at HWD. The problem is referred to engineering and repairs will be included with other structural repairs associated with the RTV coating job in 2007.

2006-11-28
HWD GT AVR Problems (Wayne's Report)
Called in Nov 28. AVR problems; Unit was on generation 40.78 MW 20.49 MVARS. On the AVR we had "Warning" Prot. Rectifier O C
I guess we were up to the limits on the AVR. on the way its set up, or we may need to get ABB back and make further adjustments. On the computer for unit we had AVR fault, diode failure alarms. ECC just had general alarm. Once the load was dropped a little I managed to reset AVR alarms.
Called in Nov 29. GGA on generation, ECC required GGB for generation. Tried GGB several times, kept tripping on in-complete sequence, flame failure. Called G. Lyver for mechanic & technican.
When Mike & Leon arrived on site, we gave GGB a dry water wash to make sure no fuel left in engine, Tried ignitors, stroked fuel valve to make sure it was working. Tried GGB again still getting incomplete sequence alarms.
After lunch ECC took unit GGA of generation, and put unit on sync cond.
We then decided to try GGA for comparsion purposes with GGB. We then got govenor pressure low alarm, and fuel forwarding system trouble alarms.
Now both GGA & GGB are down. Unit on sync cond.
In checking out the fuel system alarm we discovered the differential across the filters in the fuel forward pumphouse was up to 15 PSI. We also discovered
the motorized fuel valve up by the main fuel tank was stuck 1/2 way between opened and closed. We operated the valve in manual several times and managed to free it. It then went to the correct position, closed. thus

eliminating
the fuel system alarms.
Tried GGB, managed to get it up for the supper peak period as requested by ECC.
After unit was put back on sync cond we changed the fuel filters in the fuel forwarding
pumphouse. Since Nov 10, we have consumed 250000 liters of fuel.
When ECC let us have unit down completely we changed the filter on the fuel valve for
GGA. We need the unit completely down for this. This process allowed us to correct the
problem with govenor low pressure alarm on GGA..
We them ran GGA up to 5 MW, no alarms, Ran GGB up no alarms, then we put unit back in
Supervisory both ends available.

2007-01-07
HWD GGA Vibration Trip
Generator vibration when started with GGA.
Note from Hughie to Engineering
I would like for you guys to investigate this vibration problem at Hardwoods as noted below. In a discussion with Wayne Snow he informed me that ECC tried to start End A to put unit on synch condense but it tripped on vibration. Wayne was called out and he asked ECC to start using End B and the unit went on without a problem. He then had end A started and placed on generation mode without a problem. He also indicated that later after the event, end A was used to place Hardwoods on the system in synch condense without incident. According to Wayne this is not the first time this has occurred and it appears to occur at times when an engine is sitting idle for some time.
Could you guys have an engineer from each of your groups (preferably Nelson and Craig) assigned to investigate this to determine if this is a true vibration problem or a problem with the monitoring equipment.
Also with respect to the monitoring equipment we know we are having a problem with spare parts and Craig had prepared an estimate and we would like for you guys to expedite the development of the unbudgeted Capital Job to have the vibration equipment replaced at both sites (HWD and SVL).

2007-02-13
HWD GT Fuel leak into sump.
On Tuesday, Feb 13 it was discovered that fuel was leaking into the sump. Source of the leak was a failed auto-drain and pilot drain valve associated with the oil water separator filter in the fuel line wher the fuel exits the fuel forwarding building to the units. New valve and associated parts are on order and the auto-drain valve is temporairly closed with a manual valve. Amount of fuel lost to the sump was 75 cm rise (638 liters) (sump size is 86 cm X 99 cm). This event resulted in generation being unavailable from Tuesday, Feb.13 to late Thursday, Feb.15.

2007-02-08 / 09
HWDGT
Failed starts were experienced on both GGA and GGB. It was identified the fuel recirc heater was tripping and also the liquid fuel valve start position has to be adjusted. Weather at the time was extremely cold (-20 deg C).
Also identified a problem with the air solenoid for End A snow doors , END A was not available for starting for synch condense or for generate until a new valve is installed . The valve will be flown in overnight and will be installed on the unit in the morning. The unit is expected to be back to full availability by lunch time.

2007-03-14
HWD GT
GGB snow doors failed to operate. air lines to snow doors on GGB found

deterioriated and it is scheduled to replace braided air lines on both GGA and GGB snow doors.

2007-03-15
HWDGT
Investigation of sump at HWD identified the fluid being collected in the sump is fuel. Sump was pumped on Monday, March 12 at 1500 hrs. When dipped on Thursday, March 15, 30 cm of fuel had collected. Investigation on Thursday evening identified the source of fuel release was a failed pressure relief valve in the out line of the fuel re-circ heater. Relief valve to be replaced on Friday morning, 2007-03-16.

2007-03-20
HWDGT
Three failed starts due to incomplete sequence and failed ignition.

2007-02-22
HWDGT
Failed start. Exhaust door trip due to ice on limit switch.

2007-03-26
HWDGT
GGB failed start due to failed ignition.

2007-04-02
HWDGT
ECC ran up unit to 47 MW this morning, then , we got atrbfjbhi alarm. (Turbine A front
Journal brg high temp alarm). It registered 104 degrees C.
The same brg on B end was low seventies.
Temperature testing done on 2007-04-04. Temperatures were OK until we reached 20 MW's, then it went snakey. Unit tripped at 23 MW's. Will have trends for you tomorrow. Steve and I suggested to limit load to 20 MW until further investigation is carried out. Informed ECC of situation.

2007-04-04
HWDGT
Station inspection identified a deflector ring ahd been ejected from the Gas Turbine End B. Outage was scheduled for 2007-04-05 and inspection found the bottom ring on GGB was missing. Ring was replaced with new and at the same time the upper half was inspected . Bolts were found loose on the upper half as well. Outage sdheduled for 2007-04-13 to inspect deflector ring on GGA. Outcome will determine if SVL requires inspection as well.

2007-04-07
SVLGT
GGB was given a start and when run speed was reached a vibration alarm became active on the exciter. Alarm reset and unit continued to operate in sync condense. The accelerometer for this sensing point was replaced Feb. 7, 2007 when vibration testing was performed and the unit output was low. On 2007-04-09 the accelerometer was switched with the clutch unit in the same vicinity and the vibration followed to the clutch. Awaiting on anothere new accelerometer from HWD to confirm suspicions.

2007-04-09
HWDGT
Failed start on GGB. Attempted a start on GGA and experienced GEN Vibration alarm which operated several times before load was increased and at which point it reset. Vibration testing was completed last week and Bob Stoyles will forward information to Engineering.

2007-04-20
SVL Exciter Vibration Alarm
Replaced accelerometer on exciter and alarm still active on exciter when GGB starts and is engaged. Will arange for shaker table to test new accelerometer to confirm it is working properly. Engineering is aware of

the situation and reviewing setting as well as a solution.
ECC notified to restrict use of GGB until problem is rectified.
Testing was performed on the new accelerometer on 2007-05-03 indicates calibration is correct.

2007-04-23
HWD GT
At 1537:58 hrs GGA was started to put unit on line in sync condense. Vibration alarms were experienced at that time. There was a no vibration alarm meaning the vibration equipment was not sensing any minimal vibration. Also saw vibration alarms on exciter and Gen side A and side B. Unit will be started on 2007-04-24 and vibration will be checked at that time.

2007-05-04
HWD GT
Inspection of deflector rings on GGA identified both top and bottom rings are completely gone with some material remaining in the bottom of the exhaust stack. Also noted that some bolts were found with the retaining wire still intact and the bolt threads in perfect condition. Talked with Robert Shandera and he will attempt to vist site with Nelson Seymour to asses situation. Also noted the bearing experiencing high temperature is located in the vicinity of the failed deflector rings.
The new deflector rings were installed be drilling and tapping all new hole and was completed on May 6 at 2200 hrs. During the outage the thermocouple was checked and cleaned as well as repairs to the wires and marr connectors removed and the correct connectors installed. It was noted the wires were damaged in such a way that there could have been partial grounds on the cables during operation. At 2300 hours on 2007-05-06 GGB was test run to 100% fuel valve for a maximum output of 24.36 MW and the front journal bearing temp was 40 deg C while the rear journal bearing reached 85.5 deg C. These temperatures are consistant with the historical data and the trend data indicated a smooth rate of rise.

2007-05-10
SVL GGA
Unit failed to start due to air regulator problems in the air starter circuit. Main regulator replaced and repairs made to other regulator and valves. Regulators not working correctly due to internal parts sticking.

2007-05-30
HWD GT
Alba Power at HWD to perform inspection of GGA and GGB.Below is Nelson's notes from inspection.

HWD GGA

| | |
|---|---|
| May 30, 2007 | Alba Power did boroscope inspection of LP and HP compressor blades, cans and turbine blades. Said they normally ultrasonic clean burners after boroscope. We opted not to clean burners at the time because we were not having any temp problems. All looked OK except 2 turbine blades had a chunk of meal missing. These blades can be individually replaced but is a factory job. Alba will confirm with report. |
| May 31, 2007 | Reg replaced burners and did load test. Tripped on high EGT at 1.5 MW at 8:00 pm. |
| June 1, 2007 | Test ran engine again with Alba Power on site. Tripped again at about 1.5 MW due to high EGT. All individual temps looked good except thermocouple no. 7 which was very high and causing the excessive spread deviation. Removed and inspected thermocouple. Looked fine. Swapped thermocouples no. 7 and 8 and test ran engine. Tripped again at 1.5 MW. All thermocouple temps looked fine except no. 8 which was very high and causing problem. Replaced with spare unit and test run again. No. 7 thermocouple remained excessively hot. |

| | |
|---|---|
| | Decided to remove no. 8 burner, clean and reinstall. No.7 thermocouple reads the hot gas from no. 8 burner.<br><br>Noticed a long crack in the bellows between the engine and the power turbine. Needs to be repaired/replaced. We have a spare in stock. |

HWD GGB

| | |
|---|---|
| May 30, 2007 | Alba did boroscope inspection of LP & HP compressor blades, cans and turbine blades. A spacer piece is missing from the HP compressor blades and a also another component appears out of place (spring component that helps secure blades in place).Condition of compressor blades and cans looked O.K. Turbine blades showed some discoloration which appeared to be from improper flame pattern. Alba recommended checking the fuel distributor. Also suggested putting a gauge on both the primary and secondary fuel supply hoses to a burner to measure pressure. They know what it should be. Alba recommended nobody enter the engine compartment while the unit is running until the spacer issue is resolved. HP compressor blade spacers should be able to be replaced on site. Alba to confirm in report.<br><br>The large band clamp connecting the air intake cone o the LP compressor was loose and a separation had occurred. Reg repaired. |
| May 31, 2007 | Reg reinstalled burners and did a load test. Results same as before. Went into alarm at about 22.5 MW. |

When burmers were re-installed in GGA, high temperatures ere experienced. All burners were removed and ultrasonically cleaned. At 2041 hrs on 2007-06-02 GGA was run to 24.2 MW, fuel valve opened 100%, and spread was 28.6 degrees C.

2007-06-06/07
SVL GT
Alba Power on site to perform boroscope inspection of GGA and GGB through the removed fuel nozzles and also through the air intake at both ends.

2007-06-09
SVL GT
Generator high temperature alarm experienced while the unit was online in sync condense mode. To enable investigation the emeregency air doors for the generator were opened so the generator glycol cooler could be shut down. As of 2007-06-26 work to determine cause of heating includes:
1) Testing air flow through rad fins. Ongoing.
2) Testing glycol flow through piping system. Ongoing.
3) Breakdown and inspection of 3-way mixing valve. Valve requires replacement due to scouring and controls not functioning but indications are it is not the cause of generator high temperature.
4) Check and adjust pitch on cooler fan blades. Adjustment required and further repairs required to a blade.
5) Identified paint overspray on fan blades and cooling rad fins. Effects to be determined.
6) Identified sand blastings silica accumulated inareas between the rad cooling fins. Cooling ongoing and effects to be determined.
7) Identified severe rusting of support beams and structure of cooler

housing. Engineering to investigate and determine a solution as well as determine if it has any effect on the cooling problem.
Overall investigation is continuing to determine the specific cooling issue or if it is a combination of several accumulated problems.

2007-06-29
SVL GT
MLO Cooler
Operator identified cracks in welding that attaches the rad fan and blade assemblies to the cooler housing. Request engineering to assess both coolers for structrual integerity.

# SVL Gas Turbine Work Order History

| Date | Event | Details |
|---|---|---|
| 8/11/2006 | Anti -Ice Valve GGB | Removed and shipped to HWD, HWD GGA failed |
| 7/5/2006 | Compressor A Failure | New piston rings, seals and gaskets |
| 4/27/2006 | GGB Burners EGT | Removed and sent to Rolls Royce for inspection |
| 3/30/2006 | GGB Burners EGT | Installed burners in GGB that were removed from HWD GGB |
| 3/27/2006 | Compressor A Failure | Replaced damaged box cable |
| 3/21/2006 | Compressor A Failure | Replace flexible air line |
| 3/21/2006 | Compressor B Failure | Replace flexible air line |
| 3/16/2006 | SVL GT Trip | Logic for EGT modified |
| 3/10/2006 | Access Doors | Enlarge access covers on GGA & GGB |
| 3/10/2006 | Lube oil pump Fail | Replace bearing |
| 3/6/2006 | EGT alarm GGB | Modify logic |
| 2/28/2006 | Failed start GGA | Adjusted fuel transducer |
| 2/23/2006 | GGA loading | replace fuel strainers anf filters |
| 2/22/2006 | Failed Control display | Replaced monitor |
| 2/7/2006 | GGA GGB EGT Spread | Modified fuel flow logic |
| 2/2/2006 | GGB Combustor Cans EGT | replaced with overhauled cans (8) |
| 1/25/2006 | Fuel Meter Fail | Meter replaced |
| 1/18/2006 | GGB EGT Spread | Remove / test thermocouples |
| 1/15/2006 | GGA GGB EGT | Inspection by Rolls Wood |
| 1/15/2006 | GGB EGT Spread | replace strainer and banjo assemblies |
| 11/2/2005 | Air leak | Replace gasket on receiver |
| 10/27/2005 | GGB EGT Spread | Cleaned burners |
| 10/27/2005 | Gen Fail | Check exciter straps |
| 10/3/2005 | GGA GGB EGT | Logic revised |
| 8/4/2005 | GGA Sync Fail | Adjusted fuel valve |
| 7/15/2005 | Printer fail | Replace cable |
| 6/2/2005 | Gen alarm | ??? |
| 4/21/2005 | GGB Fuel Actuator | Install Heat tracing |
| 4/13/2005 | Air receiver A & B | Replace pressure relief valve |
| 4/12/2005 | Air receiver A | Replace failed pipe |
| 4/7/2005 | Lube Oil Sys failure | replace pressure switch |
| 3/21/2005 | Compressor A Failure | Replace gaskets and rings |
| 3/11/2005 | Gen Exciter trouble | repair exciter metering |
| 3/10/2005 | Compressor B Failure | replaced after cooler |
| 3/2/2005 | GGB failed to start | |
| 2/28/2005 | Air dryer leak | new filters and clean valve |
| 2/21/2005 | Inlet plenium B | Repair holes in floor |
| 2/21/2005 | Fuel sys | replace transducers for overfill protection |
| 2/3/2005 | Printer fail | configer printer |
| 1/26/2005 | cooling sys modify | add conditioner |
| 1/20/2005 | GGA & GGB | repair cracks in exhaust stacks and enclosures |
| 1/19/2005 | GGB failed | fan motor repaired |
| 1/12/2005 | Sump System | Modify logic |
| 12/22/2004 | Lube Oil Sys failure | exchanger cooling fan belts |
| 10/8/2004 | GGB Exhaust leak | repairs to turbine casing flange joint |
| 10/29/2004 | Fuel forwarding trouble | |
| 10/28/2004 | GGA trip on high temp | |
| 10/28/2004 | GGA Exhaust gas leaks | Retorqued bolts |
| 10/28/2004 | GGA & GGB hot end inspection | Also cleaned fuel nozzles |
| 10/13/2004 | GGB high temp alarm | |
| 10/8/2004 | Unit controls fail | Repairs to cards in DCS |
| 9/9/2004 | 240 v battery | replaced cell |
| 8/12/2004 | Compressor A Failure | repair oil leak |
| 7/22/2004 | GGB failed to Sync | |
| 7/22/2004 | Jct Box JB7B corrodion | install heater |
| 7/15/2004 | Paint rusted fuel tanks | |
| 6/18/2004 | GGA combustion chamber drain valve | |
| 6/17/2004 | GGB combustion chamber drain valve | |
| 6/4/2004 | GGA & GGB Heaters fail | repair heater connections |
| 6/3/2004 | Battery room heater installed | |
| 4/20/2004 | Compressor A Failure | replace gaskets and oil |
| 4/15/2004 | Lube Oil Sys failure | Replace heater circuit breaker |
| 3/16/2004 | Gen Fail | inverter failed and replaced |
| 3/4/2004 | GGA & GGB start fail | fuel heating repairs |
| 2/24/2004 | GGB Sync Fail | |
| 2/23/2004 | GGA Failed start | Fuel valve adjusted |
| 2/18/2004 | Printer failed | Changed settings |
| 2/11/2004 | Air dryer fail | modified output line and check valve |
| 1/27/2004 | GGA Failed start | |

| | | |
|---|---|---|
| 1/20/2004 | Annunciator fail | replaced cards |
| 12/17/2003 | AVR Floor Repaired | |
| 12/11/2003 | GGA & GGB logic changes | |
| 12/10/2003 | Lube Oil Sys failure | reset logic |
| 10/24/2003 | 250 v battery bank replaced | |
| 10/17/2003 | GGB Exhaust leak | Retorqued bolts |
| 10/10/2003 | Fuel sys leak | leaking filter |
| 10/7/2003 | Generator cooler fail | belt replaced |
| 9/30/2003 | GGA Failed start | adjusted fuel transducer |
| 8/28/2003 | Compressor A Failure | Head gasket |
| 8/13/2003 | Fuel sys leak | |
| 7/2/2003 | GGB failed sync | fuel valve problem |
| 6/27/2003 | Motor contactors fail | required cleaning |
| 6/18/2003 | Compressor B Failure | replace aftercooler |
| 6/17/2003 | Generator AVR repairs | |
| 5/14/2003 | GGA & GGB Inlet filter diff fail | replaced tubing and repaired switch |
| 4/30/2003 | GGB Temp Trouble | Replaced thermocouple wire |
| 4/6/2003 | Air dryer fail | Replaced check valve |
| 2/6/2003 | Unit metering fail | repairs to KWH meter |
| 2/4/2003 | GGA EGT fail | repairs to fuel pressure transducer |
| 1/28/2003 | Air dryer fail | replaced filters |
| 1/15/2003 | lube oil sys alarm | lube oil added |
| 11/1/2002 | lube oil cooler housing | repairs to screen and frams |
| 10/16/2003 | GT fuel leak | repairs to fuel valve |
| 10/10/2002 | lube oil leak | repairs to tregulator flange |
| 5/31/2002 | GGB Failed to start | Repair to oil pressure switch |
| 5/9/2002 | Install thermal assembly on fuel temp regulator | |
| 4/30/2002 | Main Fuel valve leak | replace gasket |
| 4/30/2002 | GGA & GGB EGT alarm | Logic changes |
| 4/16/2002 | Fuel level fail | Transmitter fail |
| 4/4/2002 | GT unavailable | TRF SS1 high temp alarm |
| 3/15/2002 | GT Control fail | Switch replaced |
| 3/5/2002 | Clutch fail | Solenoid checked |
| 2/4/2002 | Fuel metering fail | Calibrate meter |
| 12/12/2001 | GGA fuel valve repair | |
| 12/7/2001 | GGB fuel valve repair | |
| 8/24/2001 | Inlet plenum A paint | |
| 7/6/2001 | Fuel tank farm | install expansion tank |
| 1/23/2001 | Exhaust A replace volute fabric | |
| 1/17/2001 | GGA & GGB Control logic adjustments | |
| 1/12/2001 | GGB sent to Rolls Wood for repairs | |
| 1/10/2001 | GGB Inlet plenum broken hinges | |
| 1/9/2001 | GGB Actuator oil leak repaired | |
| 12/8/2000 | Compressor A Failure | new gaskets and rings |
| 11/22/2000 | GGB Exhaust gas bellows replaced | |
| 11/7/2000 | Mube oil sys fail | replaced timer |
| 9/22/2000 | GGA Exhaust gas bellows replace | |
| 8/9/2000 | GGB Actuator repair | |
| 6/28/2000 | Generator fail | Bushing replaced |
| 5/18/2000 | cooling sys fail | repair glycol pump |
| 5/18/2000 | GGA & GGB hot end inspection | With Rolls Royce rep. On site |
| 4/27/2000 | Compressor B Failure | new gaskets and rings |
| 3/13/2000 | Generator alarm | Heater fail |
| 3/9/2000 | Clutch A fail | locking solenoid fail |
| 1/6/2000 | Clutch A & B Heaters not working | |
| 12/20/1999 | Fuel off loading | repair start button |
| 11/3/1999 | Exhaust A replace volute fabric | |
| 9/10/1999 | Low volts DC alarm | |
| 9/2/1999 | Inlet plenum floor paint | |
| 9/1/1999 | GGB removed and shipped to HWD | |
| 8/16/1999 | Cooling sys motor overhauled | |
| 3/24/1999 | Datalogger fail | |
| 1/1/1900 | Cooling sys leak | Replace pump seals |
| 3/30/2001 | GGA damaged burner | replaced |
| 7/24/2001 | Fuel tanks | Installed level transmitters on all tanks |
| 9/15/2006 | GGA & GGB Repair and paint structure | |

# SVL Gas Turbine Station Log History

| Date | Event | Details |
|---|---|---|
| 1/20/1992 | GGA & GGB Sync Fail | Speed control problems |
| 2/26/1992 | GGB Sync Fail | Governor Problems |
| 2/28/1992 | GGB Sync Fail | Clutch problem |
| 3/10/1992 | GGB Sync Fail | Control card |
| 4/27/1992 | GGA Shut | Fuel filter leak |
| 6/8/1992 | GGB LP Compressor vanes removed | To Roll Royce for repairs |
| 8/31/1992 | Unit Tripped | Low oil pressure |
| 9/21/1992 | Unit shut | Replace Tacometers & repair snow door electrics |
| 9/22/1992 | GGB lube oil pressure | replace switch |
| 12/10/1992 | Failed to sync | Governor Problems |
| 3/31/1993 | GGA Inspection | Performed by Rolls Royce |
| 4/1/1993 | GGB Inspection | Found 3 can straps starting to burn |
| 5/12/1993 | Gen trip | Unit lockout and reverse power |
| 7/26/1993 | Gen trip | Component failures in control cct, vibration monitor & governor |
| 7/30/1993 | GGA & GGB Unavailable | Air supply problems and control component failures |
| 8/5/1993 | Gen removed from service | Failed lightning arresters and bus |
| 8/9/1993 | GGA Fail | Vibration monitor problem |
| 8/10/1993 | GGA & GGB | Vibration monitor problem |
| 8/17/1993 | GGA & GGB Loading problems | Woodward rep on site to look at load sharing |
| 8/23/1993 | Gen out of service | Jacking pump failure |
| 5/30/1993 | GGB Alarm | Low fuel pressure |
| 10/6/1993 | Sync Cond trip | AVR undervoltage, blown fuse |
| 10/13/1993 | GGA Unavailable | Air starter regulator repairs |
| 10/20/1993 | Generator removed from service | DC ground problem |
| 10/22/1993 | GGA fail | ignition problem |
| 11/4/1993 | GGA Removed from service | replace ignitor |
| 12/16/1993 | GGB Fail to start | Governor Problems |
| 12/25/1993 | Generator trip | Fault on 138 kv bus returned to service 1994-02-23 |
| 1/7/1994 | G1T1 repairs | Sent to manufacturer for repairs |
| 3/12/1994 | GGA Failed start | Snow door problem |
| 3/28/1994 | GGA Failed start | Nnknown reason |
| 3/29/1994 | GGB removed from service | Replace thermocouple |
| 4/3/1994 | GGB removed from service | Lube oil filter blocked |
| 5/31/1994 | GGB failure | Ait starter leak |
| 7/2/1994 | GGA Failed start | Peroblem with exhaust doors |
| 7/5/1994 | Sync Condense trip | Control relay failure |
| 7/6/1994 | GGB removed from service | Air supply leak |
| 7/14/1994 | GGA Failed start | Incomplete sequence |
| 7/27/1994 | GGA failed to sync | Unit breaker racking problem |
| 8/13/1994 | GGA failed to sync | Sync PT problem |
| 10/30/1994 | Generator trip | PT failure |
| 11/22/1994 | Bus duct support insulators replaced | |
| 12/11/1994 | GGB failed sync | Clutch proximity switch fail |
| 1/5/1995 | Sync Condense failure to select | Problem unknown |
| 1/13/1995 | GGA Failed start | Snow door alarm |
| 2/14/1995 | GGB failed start | Air starter failure |
| 5/30/1995 | GGA Failed start | relay failure |
| 8/23/1995 | GGB removed from service | Replace engine oil due to lab analysis |
| 9/11/1995 | GGA New air filters system | 8 days |
| 1995-19-27 | GGA New air filters system | 8 days |
| 10/11/1995 | Gen unavailable | Faulty datalogger |
| 19995-10-12 | Generator unavailable | AVR failure |
| 10/23/1995 | Replaced unit MVAR meter | |
| 12/14/1995 | Generator unavailable | Woodward rep on site to look at Isoc / Droop loading problems |
| 1/1/1996 | GGB failed start | Control relay problems |
| 1/3/1996 | GT max load 35 MW | Woodward rep visit site. Found loose connection on A ph PT primary finger contact |
| 1/16/1996 | Generator unavailable | Droop load sharing problems. Card replaced in controls |
| 5/31/1996 | GGA Removed from service | Repair air starter |
| 7/2/1996 | GGB fuel leak | Engine fuel line replaced |

| | | | |
|---|---|---|---|
| 9/11/1996 | Generator removed from service | Datalogger fail | |
| 7/14/1997 | GGB failed start | Starter Failure | |
| 7/22/1997 | GGB failed start | Air regulator problem | |
| 9/2/1997 | Sync Condense trip | Halon sysatem malfunction | |
| 2/20/1998 | GGA Removed from service | Snow door problem | |
| 5/20/1998 | Generator sync fail | Blown fuse | |
| 5/23/1998 | GGA & GGB Trip | DC breaker trip | |
| 7/1/1998 | Sync Concense trip | T1 lockout due to Gen bushing failure | |
| 8/24/1998 | Sync condense trip | Problem with voltage (64B) cct | |
| 11/23/1998 | Unit shutdown | Install new fuel meter | |
| 1/3/1999 | Sync Condense trip | High temp due to cooling pump fail | |
| 1/19/1999 | Unit removed from service | Fuel meter problem | |
| 5/25/1999 | Unit removed from service | Install new DCS system, returned to service 1999-08-11 | |
| 10/24/2000 | GGB Out of service | Engine in Scotland for repairs since Sept. 7, 2000 | |
| 10/24/2000 | GGB Bellows changed out | Bellows taken from GGB and installed on GGA. Faulty bellows sent to St. John's for repairs. | |
| 10/26/2000 | Contaminated soil | Contaminated soil removed from tank farm in Sept, 2000. | |
| 11/6/2000 | Coolant alarms | Glycol fan failure | |
| 12/1/2000 | Hoist repair | GGA & GGB 5 ton hoist sent to Dover Crane for repair | |
| 1/5/2001 | GGB returned and inatalled | Returned from Scotland | |
| 1/16/2001 | GGB EGT spread trip | Tuning and making adjustments with Craig Warren next 2 days | |
| 1/17/2001 | GGA Clutch problem | Clutch had to be dis-engaged manually by mechanic | |
| 1/22/2001 | GGA Outage | Replace exhaust fabric | |
| 1/23/2001 | GGA Burner #4 loose shroud nut | | |
| 2/22/2001 | Lube oil high temp and low level alarm | oil added | |
| 3/8/2001 | Unit Tripped | Main lube oil temp / low level alarm | |
| 3/30/2001 | GGA Burner # 4 replaced | | $8,000.00 |
| 5/15/2001 | Fuel Sys Problems | All three fuel transmitters sent away for calibration | |
| 5/28/2001 | GGB tripped | EGT trip | |
| 5/28/2001 | GGA failed start | Incomplete sequence | |
| 5/28/2001 | GGB tripped | EGT tripped several attempts | |
| 5/29/2001 | GGB start fail | Fuel transducer | |
| 6/7/2001 | GGB failed start | ignition problem | |
| 6/8/2001 | GGB Fuel transducer adjusted | | |
| 9/19/2001 | GGA Low fuel pressure alarm | Filters replaced | |
| 11/5/2001 | GGA Alarms | Temp alarms in Turbine BRG, Lube oil and Gas Gen Enclosure | |
| 11/29/2001 | GGA Trip | Speed sensor fail | |
| 12/4/2001 | GGB failed start | Solenoid burnt out | |
| 12/4/2001 | Sync Condense trip | Glycol pump fuse blown | |
| 12/4/2001 | GGA Clutch fail | Mechanic had to disengage manually. | |
| 12/5/2001 | GGB failed start | Liquid fuel valve position fail | |
| 1/10/2002 | New Energen system in service | | |
| 1/31/2002 | Generator trip | Reverse power | |
| 2/22/2002 | GGB failed start | Low DC volts alsrm | |
| 2/27/2002 | GGA Temp alarm | Failed thermocouples | |
| 3/5/2002 | GGA Clutch solenoid replaced | | |
| 3/5/2002 | GGA Failed start | Low fuel pressure. Filter replaced | |
| 3/5/2002 | Main lube oil temp alarm | Failed regulating valve | |
| 3/15/2002 | ECC unable to select sync condense to generate mode | Logic problem | |
| 4/4/2002 | SS1 High Temp Alarm | RTD connections failed | |
| 4/20/2002 | GGB tripped | Lube oil pressure switch fail | |
| 4/30/2002 | GGB Logic changes made by Engineering | | |
| 5/7/2002 | Fuel leak | Fuel filter o-ring replaced | |
| 5/30/2002 | GGB failed start | Failed lube oil pressure switch | |
| 9/18/2002 | Fire dampers on GGA & GGB replaced | | |
| 10/16/2002 | GGB Fuel valve fail | Faulty microswitch | |
| 10/24/2002 | Alarm, Unit not ready | Air system failure | |
| 11/2/2002 | Generator trip | Reverse power | |
| 11/15/2002 | Sync Condense trip | Main lube oil pump leak | |
| 11/26/2002 | Air dryer fail | Broken prefilter | |
| 11/29/2002 | GGB not operational until GGB oil is changed | | |

| | | |
|---|---|---|
| 1/27/2003 | Alternator cooling problem | Fan motor failure |
| 1/28/2003 | Dryer assembly replaced | |
| 1/29/2003 | GGA, GGB and alternator not available | Main lube oil alarm. Faulty relay in heater |
| 1/30/2003 | GGA EGT trip | |
| 1/31/2003 | GGA trip | Fuel pressure switch failure |
| 2/14/2003 | GGB trip | Exhaust door failure |
| 2/14/2003 | GGB Fail to start | Hydraulic actuator malfunction |
| 3/14/2003 | Fire impairment | Water supply from town frozen, restored 4/28/2003 |
| 3/27/2003 | 250V battery trouble | Cell #14 & 56 removed |
| 4/7/2003 | Unit control problems | Monitor and keyboard failure, returned to service 5/14/2003 |
| 4/21/2003 | GGB trip | Reverse power |
| 4/25/2003 | GGA failed start | |
| 4/30/2003 | GGA failed start | |
| 6/18/2003 | MCC contactors trouble | Required cleaning |
| 6/29/2003 | GGB failed start | Auto sync trouble |
| 6/29/2003 | GGB failed start | EGT high |
| 6/30/2003 | GGB failed start | Fuel transducer adjusted |
| 8/22/2003 | GGB EGT trip | |
| 9/18/2003 | GGA EGT trip | |
| 9/30/2003 | GGA failed start | Fuel transducer problem |
| 10/6/2003 | Cooling system failed | Fan motor belts replaced |
| 10/15/2003 | Gas generator | Retorqued flange bolts on power turbine casing |
| 10/24/2003 | 250V battery bank replaced | |
| 11/9/2003 | GGB trip | Enclosure high temp |
| 11/9/2003 | GGA failed start | Three times on EGT |
| 12/2/2003 | GGA & GGB failed start | Jacking pump blown fuse |
| 12/27/2003 | Control system failure | Inverter failure |
| 1/1/2004 | Air system failed | Dryer after filter housing failed |
| 1/5/2004 | Control system failure | Inverter failure. Removed from service |
| 1/7/2004 | Logic changes | Generate/sync condense mode |
| 1/7/2004 | GGA failed start | Light off problems. Fuel transducer adjusted |
| 1/7/2004 | GGB snow doors failed to close | Operating pressure adjusted |
| 2/2/2004 | GGB failed sync | Control problems |
| 2/16/2004 | GGA failed start | Failure to light off |
| 2/18/2004 | Printer replaced | |
| 2/22/2004 | Main lube oil temp alarm | Heater breaker tripped |
| 2/25/2004 | Fire relay for glycol pump replaced | |
| 3/4/2004 | Fuel re-circ heater returned to service | |
| 3/12/2004 | New inverter in service | |
| 3/19/2004 | Fuel re-circ heater logic changes | To prevent heater from staying on if unit trips |
| 4/19/2004 | Lube oil pressure alarm | Filters replaced |
| 4/28/2004 | GGA & GGB power turbine | Retorqued flange bolts |
| 5/18/2004 | GGB hot end inspection | |
| 5/19/2004 | GGA hot end inspection | |
| 6/14/2004 | All three fuel tanks painted | |
| 7/16/2004 | 125V battery bank removed from service | Thermal runaway on VRLA |
| 9/27/2004 | Generator trip | Alternator main lube oil temp. Fan failure |
| 9/28/2004 | GGA EGT trip | |
| 9/30/2004 | GGA failed start | High EGT |
| 10/2/2004 | GGB shutdown | Auto sync trouble |
| 10/8/2004 | DCS logic changes | |
| 10/13/2004 | GGB EGT trip | Fuel actuator adjusted |
| 10/13/2004 | GGA clutch failure | Proximity switch fail |
| 10/18/2004 | GGB failed start | Fuel transducer |
| 10/21/2004 | New 125V battery bank in service | |
| 12/7/2004 | GGA trip | Liquid fuel failure |
| 12/7/2004 | GGB EGT trip | |
| 12/7/2004 | GGA failed to light off | |
| 12/7/2004 | Generator trip | Reverse power |
| 12/13/2004 | GGA failed start | |
| 12/13/2004 | Main lube oil failure | Relay failure |
| 1/12/2005 | Sump level logic modified | |
| 1/13/2005 | Computer repairs | New power supply fan |

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|---|---|---|
| 1/19/2005 | GGB enclosure fan motor replaced | |
| 1/20/2005 | GGA GGB exhaust stack repairs | Cracks repaired |
| 2/22/2005 | GGB failed start | Generator overspeed trip. Actuator adjusted |
| 2/23/2005 | Generator trip | High bearing temperature. Blown fuse |
| 2/23/2005 | GGB EGT trip | |
| 2/23/2005 | GGA EGT trip | |
| 3/8/2005 | Main lube oil control relay failure | |
| 3/9/2005 | Compressor #2 fail | After-cooler replaced |
| 3/14/2005 | Air receiver tank #1 severe leak | Tank isolated and removed from service and repaired by contractor |
| 6/2/2005 | Sync condense trip | DC ground |
| 6/23/2005 | Start sight assessment for hydrocarbons | |
| 8/3/2005 | GGB failed start | Exhaust thermocouple quality |
| 8/3/2005 | GGA failed start | Sync trouble |
| 9/2/2005 | Generator trip | Reverse power |
| 9/2/2005 | GGB EGT trip | |
| 9/15/2003 | GGB failed start | High EGT |
| 10/3/2005 | Control logic changes | |
| 10/25/2005 | Generator excitor failure | Blown fuses. Failed excitor straps |
| 10/27/2005 | GGB EGT trip | Burners #1 & 4 cleaned with no success |
| 10/27/2005 | GGA failed start | Liquid fuel valve position fail |
| 10/28/2005 | Fuel transducer adjusted | |
| 11/2/2005 | GGA air starter leak repaired | |
| 11/14/2005 | GGA hot end inspection | Engineering and Rolls Royce on site |
| 11/15/2005 | GGB hot end inspection | Engineering and Rolls Royce on site |
| 11/21/2005 | Fuel meter replaced | |
| 11/23/2005 | GGA failed start | EGT spread |
| 11/26/2005 | GGB failed start | Failed to light off |
| 12/1/2005 | GGA & GGB logic changes | |
| 12/2/2005 | GGA failed start | EGT spread |
| 12/16/2005 | Emergency diesel installed | |
| 1/3/2006 | Cooling failure | Main lube oil temp. Belts replaced |
| 1/16/2006 | GGA failed start | EGT |
| 1/19/2006 | GGB fuel nozzles removed and sent to the UK for overhaul | |
| 1/23/2006 | GGA failed start | Adjusted fuel transducer |
| 1/24/2006 | GGA failed start | EGT spread |
| 1/25/2006 | GGA sync condense | Three attempts before success |
| 1/30/2006 | GGB combustor cans | GGB combustors cans replaced with refurbished set stored at HWD. Rolls Royce rep on site |
| 2/2/2006 | GGA failed start | EGT spread |
| 2/5/2006 | GGA failed start | EGT spread |
| 2/6/2006 | GGA failed start | EGT spread |
| 2/6/2006 | GGA fuel trandsucer adjusted twice | |
| 2/7/2006 | GGA logic | Engineering on site for logic changes |
| 3/6/2006 | GGB logic changes | |
| 3/16/2006 | GGA logic changes | |
| 4/5/2006 | Anti-ice valve returned to GGB from HWD | Fuel nozzles from HWD GGB installed in SVL GGB. Three attempts to light off GGB failed. Fuel transducer adjusted |
| 4/25/2006 | Snow doors repaired | |
| 6/9/2006 | Compressor #1 | New rings |
| 6/15/2006 | Replaced voltage snubbers in control circuit | |
| 8/8/2006 | GGB unavailable | Combustor cans, fuel nozzles removed from SVL GGB and sent to HWD GGB. Anti-ice valve removed from SVL GGB sent to HWD GGA |
| 8/17/2006 | GGA failed start | EGT. Three attempts. Fuel transducer adjusted |

# Hardwoods Gas Turbine Work Order History

| Date | Work Performed |
|---|---|
| 21-Aug-06 | Installed combustion cans (under supervision of Rolls Royce Rep Alain Joseph) from SVL END B in HWD END B EGT alarm at 22MW |
| 19-Aug-06 | L/P Turbine Inspection completed by Steve Press of Rolls Wood .Everything looked good.. |
| 8-Aug-06 | Exhaust stack noise reduction panels repaired. Bolts rusted off. Black and Mac performed temporary repairs. Permanment repairs scheduled for fall. |
| 4-Aug-06 | Attepted to repair leak on demister |
| 31-Jul-06 | HWDGT END A tripped following logic changes due to anti ice valve problem pulling down voltage to P/S. Anti ice valve from SVL END B installed at HWD End A. |
| 17-Jul-06 | DC ground fuel valve. Replaced corroded junction box. |
| 7-Jul-06 | Repaired drainage sump piping due to heaving from frost. |
| 4-Jul-06 | Replaced proximity switch GGA clutch. |
| 14-Jun-06 | Changed snubbers (9) in junction box for fuel system GGA & B. |
| 14-Jun-06 | Rewired anti ice power supply to increase capacity due to ongoing intermittent P/S loading down problem. |
| 5-Jun-06 | HWDGT call out - clutch problem. |
| 1-Jun-06 | Fuel leak - Replaced Jordan valve |
| 29-May-06 | Repair air dryer - Replaced Hex Air Valve |
| 26-May-06 | Repair fuel leak - Replace o-ring on filter GGA |
| 24-May-06 | HWDGT, repair leak stand by diesel unit. Replace valve cover gaskets. |
| 23-May-06 | Repair lube oil leak on vacuum pump. Replaced line from vacuum pump to demister. |
| 9-May-06 | Replace anti ice P/S as a result of a callout on May 7, 2006 due to low voltage on P/S. Calibrated spare P/S and installed. |
| 28-Apr-06 | Repaired leaks on MLO System. |
| 24-Apr-06 | Replaced bearing and shaft on #1 fan for Glycol cooling system. |
| 19-Apr-06 | HWDGT, End B swapped burners 2 & 5 and EGT alarm at 19 MW. |
| 3-Apr-06 | Repair demister leak. Replace filter gaskets and housings. |
| 3-Apr-06 | Changed solenoid GGA/GGB lube oil system. |
| 30-Mar-06 | Installed repaired anti ice valve from OZARK and shipped SVL unit back. |
| 30-Mar-06 | Replace 30A, 600V breaker for Gycol system. |
| 24-Mar-06 | HWDGT, replace burners GGB (removed burners that were installed March 6, 2006) |
| 22-Mar-06 | HWDGT, check P/S to clutch solenoid. Found problem with snubber circuit. Repair clutch on END A OK. |
| 21-Mar-06 | GGA, replace Jordan valve. |
| 21-Mar-06 | Competed adding 20 drums of TRESSO 32 bearing oil due to sump alarm on March 19. The source of this leak was the expansion joint on rear journal bearing on Turbine A. All expansion joints at HWD and SVL were inspected and tightened as required. |
| 19-Mar-06 | Investigate sump alarm at HWDGT. |

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| 15-Mar-06 | Reinstall anti ice valve from SVL and send anit ice valve back to OZART for repairs. |
| 14-Mar-06 | Replaced inverter. |
| 14-Mar-06 | Replace cable to fuel filter alarm. |
| 14-Mar-06 | Replace safety relief valve on comp "B". |
| 6-Mar-06 | Snow doors END B - replaced regulator and solenoid, 3 brackets and clamps. |
| 6-Mar-06 | HWDGT, replace burners. Installed refurbished burners in END B and sent old back to SVL. |
| 1-Mar-06 | GGA, clutch malfunction. Removed covers and unlocked clutch. |
| 28-Feb-06 | HWDGT, high press on fuel forward pump. Replace and relocate thermocouple. |
| 28-Feb-06 | Changed final fuel filter on GGA. |
| 23-Feb-06 | HWDGT, Glycol S,s #1 fan noisy. Grease bearing housing. |
| 18-Feb-06 | Replace Glycol fan belts (2 of 3) |
| 14-Feb-06 | Stand by diesel. Replaced AVR, speed pot, replaced actuator cable. |
| 14-Feb-06 | Repaired oil leak on demister. |
| 9-Feb-06 | Stand by diesel prot trip. |
| 9-Feb-06 | HWDGT, repair flow meter error message. |
| 27-Jan-06 | Install anti ice from SVL B on HWD End A. |
| 27-Jan-06 | Tested manually operation of END A and END B to determine if one end could take 25MW and other 15MW. Failed; Denoted SWDGT to 2 X 15MW = 30MW. |
| 27-Jan-06 | Fabricate 2 Jboxes, to prevent water from entering due to snubber circuit failures. |
| **21-Jan-06** | **See Jims email for detail.** |
| 20-Jan-06 | Snow Doors, repair solenoid. |
| 18-Jan-06 | Calibrate fuel meter. |
| 12-Jan-06 | Replace Jordan valve. |
| 10-Jan-06 | Checked Thermocouples on END B (to ensure exhaust gas temp are "real". |
| 20-Dec-05 | GGB replace Jordan valve. |
| 16-Dec-05 | Pumped out 240 gallons of fuel. Replaced 3 pressure relief valves in fuel forwarding system. |
| 28-Nov-05 | Repaired broken line on snow doors. |
| 18-Nov-05 | Installed flow meter. HWDGT GGB Hot End Inspection. |
| 17-Nov-05 | HWDGT, GGB invest hot burner. |
| 17-Nov-05 | Inspection of HWDGT and SVLGT by Rools Wood/ABB Rep to help with EGT problem. |
| 15-Nov-05 | Installed new 125 VDC bank. |
| 14-Nov-05 | Replaced standby diesel unit |
| 14-Nov-05 | Replaced bottom bearings on both fans. |
| 14-Nov-05 | Replace dirty alternator filters. |
| 10-Nov-05 | Failed to start. Relay burned up for starting Demister .Replaced relay "OK" |
| 8-Nov-05 | Replace burnt vib cards. |
| 27-Oct-05 | Replace rusty conduit. |
| 19-Sep-05 | HWDGT, fuel module leak/repair. |
| 19-Sep-05 | HWDGT, END B temp test. |
| 16-Sep-05 | HWDGT, END A replaced proximity switch due to clutch malfunction. |
| 15-Sep-05 | HWDGT, invest END A clutch. Checked operation, starting and stopping (intermitent problem) |
| 9-Sep-05 | Repaired fuel leak on fuel nozzle no. 7. |
| 23-Aug-05 | Repaired broken wire on field GND where it attaches to brush, (Alarm). |
| 21-Aug-05 | Snow doors, END A repaired air leak. |
| 12-Aug-05 | HWDGT, programed logic for motorized fuel valve. |
| 8-Aug-05 | HWGT END A, clutch alarm. Replaced proximity switch on END A and ok. |
| 5-Aug-05 | Replace sump drain lines. |

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| 4-Aug-05 | Hot end inspection performed. W/O 385531 |
| 3-Aug-05 | Upgrade fuel system for stand fuel to connect to sump drainage system. |
| 27-Jul-05 | Contractor install new supply and return lines from fuel forwarding BLDG to END A and END B due to a fuel leak discovered on June 9, 2005 during escavation to tie diesel building drainage system into sump system. |
| 28-Jun-05 | Snow doors, replace all flex. Line on snow doors. Replace rusted air cannisters and filters. |
| 22-Jun-05 | Pressure tested lines and discovered Sup/Ret lines were pitted and leaking |
| 14-Feb-05 | Reparred air leak on snow doors. |
| 27-Jan-05 | Reparied fuel leak - FF BLDG - Replaced air trap for main fuel filter. |
| 8-Nov-04 | HWGT, repaired fuel leak and pressure tested. |
| 14-Sep-04 | Call in - Loss of ready lights. Low temp on MLO, reset unit OK. |
| 9-Sep-04 | Call out - computer locked up unit at 40MW ECC had alarms but could not be seen locally. Had to re-boot. |
| 27-May-04 | HWGT, replaced AVR voltage adjust motor. |
| 16-Apr-04 | HWDGT, repair fuel leak. |
| 10-Apr-04 | Replace alternator filters. |
| 7-Apr-04 | HWDGT, JB-3 replaced term strip and wiring |
| 1-Apr-04 | Repaired float switch for sump |
| 12-Mar-04 | Glycol cooling system - installed 2 inspections hatches |
| 12-Dec-03 | HWDGT would not start due to vibration alarm. Tightened monitoring bolts on vib detec. |
| 5-Nov-03 | HWDGT, intermitent GT fire system alarm. (NF Power system problem and when power would go off, alarm would come in. |
| 20-Aug-03 | HWDGT GGA, Replace proximity switch clutch A. |
| 18-Aug-03 | GGA, installed overhauled burners that were sent to Rolls Wood in June, 2003. |
| **20-Jun-03** | Replaced main lube oil heat exchanger. |
| **12-Mar-03** | HWDGT END A Problem with EGT at 22MW. |
| **5-Mar-03** | GGA perform hot end inspection by R.R. up |
| 9-Dec-02 | GGB repaired Jordan valve. |
| 10-Oct-02 | Replaced shaft on main fuel pump #1 |
| 27-Sep-02 | Change logic for EGT trips/alarms as per Craig Warrens request. |
| 19-Sep-02 | Repair oil leak on main supply line to main tank (contractor completed HP welding) |
| 19-Apr-02 | Repair demister leak. |
| 18-Apr-02 | Repair leak on #1 fuel forwarding pump. |
| 10-Jan-02 | Repair leak on Jacky pump GGB |
| 19-Dec-01 | Replace and repair Jordan valve GGB. |
| 14-Nov-01 | GGA, Repair leak on Jordan valve. |
| **29-Oct-01** | GGB tripping on single exhaust thermocouple. All thermocouples are reading high on END B. |
| 22-Oct-01 | Repair oil leak on demister |
| 18-Oct-01 | Repair leak on jacky pump, GGA |
| 18-Oct-01 | Replace limit switch on blow in doors. |
| 28-Sep-01 | Elect. Switch for sump replaced. |
| 24-Sep-01 | Can not control voltage on unit |
| 4-Jun-01 | Fuel leak repair fillter housing GGB |
| 15-Mar-01 | Check and repair DC GND |
| 9-Mar-01 | Trouble MLO - found belts broken on Glycol cooling fan #1 |
| 14-Feb-01 | Installed new invertor. |
| 25-Dec-00 | Starting problems on Xmas Eve and day. Eventually got END B ON. |

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| 18-Dec-00 | Inverter and DC GND. GND on the A END governor motor. Flex conduit from motor to JB was replaced. |
| 8-Nov-00 | Replaced and tapped broken proximity Switch cover and replaced Prox switch due to clutch A problem. |
| 17-Oct-00 | Point fuel storage tank. |
| 6-Oct-00 | Replaced safety valves on both receivers. |
| 2-Oct-00 | Replaced oil seal on MLO pump #1 |
| 28-Aug-00 | HWDGT, GGA, oil alarm. Adjusted Glycol regulator. |
| 9-Jun-00 | Replace mech seal and o-ring on main fuel forwarding pump. |
| 17-May-00 | RR Rep complete hot end inspection on A & B |
| 27-Apr-00 | Due to vibration problems GGA was sent to Scotland for repairs. |
| 30-Mar-00 | Test thermocouples on EGT A & B 200°C, 400°C, 600°C using oven form HRD plant. All temp within 3% of oven settings. HWGT A & B, recalibrate exhaust thermocouples due to END A tripping EGT. |
| 24-Dec-99 | Clutch A-Repair |
| 8-Dec-99 | HWDGT, repaired thermostat valve on Glycol system |
| 1-Dec-99 | HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed. |
| 30-Nov-99 | HWDGT, GGA fail to start. C. Warren made logic changes due to BRG/ lube temp trip and alarm being reversed. |
| 30-Sep-99 | Replaced air filters. |
| 10-Sep-99 | Install GGA that was removed from SVL. |
| 18-Jun-99 | HWDGT, AVR/Exciter trouble AVR 1 & 2 tripped due to 400A fuses in exciter. Four of six fuse, had to be replaced. |
| 15-Jun-99 | HWDGT, repair demister leak. |
| 15-Jun-99 | Change alternator filters. |
| June 3-8, 1999 | Investigate lube oil trip.Raised High temperature alarm, shut down and trip from 75-100, 80-105, 90-115 on A and B. Change filter on GGA and GGB lube system. |
| 21-Apr-99 | Investigate sequence failure/ignitor END A. Adjust sequence fail ignitor form 10-12 sec. |
| | |
| 8-Mar-99 | Call out - Sync cond trouble, alarm on shut down. Alarm reset okay. |
| 28-Feb-99 | Auto Sync Trouble - Callout Reset Okay. |
| 20-Feb-99 | Callout - Loss of control of Gas Turbine Aux relay in IRD (KS) faulty. |
| Mar 12 & 14, 1999 | Auto sync trouble alarm on start down fo sync condense on March 12 and twice on March 14, 1999, March 23 & 24. After consulting with eng. 1. Sync trouble 2. Auto Sync trouble 3. Stator temp low were disabled to ECC's alarm page. |

# Hardwoods GAS Turbine Station Log History

| Date | Event | Details |
|---|---|---|
| 1/9/2002 | GGB Fuel leak | Fuel pump repairs |
| 1/9/2002 | Fuel system trouble | Fuel heater not working |
| 1/11/2002 | GGB Fuel leak | Fuel pump repairs |
| 1/18/2002 | Air Temp Regulators | Replaced temperature probe |
| 1/24/2002 | GGA & GGB failed start | Several attempts Incomplete sequence Failed to light off |
| 1/25/2002 | Lube oil problems | Replaced oil gauge on MLO pump # 1 |
| 1/29/2002 | GGB Trust Bearing Trouble | Thermocouple failed |
| 1/31/2002 | GGA & GGB failed start | Incomplete sequence Had to run lube system in manual prior to start to warm oil |
| 2/5/2002 | Lube oil problems | Re-circulated oil and governors to maintain temperatures |
| 2/8/2002 | GGA & GGB failed start | Incomplete sequence. No flame. Had to run oil and governor pumps for temperature |
| 2/10/2002 | Failed to start | Dc ground. Failed control relay. |
| 2002--02-12 | Berairgs low temp | Circulated oil to warm up. |
| 2/13/2002 | Failed start | Incomplete sequence. No flame. Had to run oil and governor pumps for temperature |
| 2/13/2002 | DC ground | Failed control relay |
| 2/14/2002 | Lube oil problems | Low temperature. Installed heat tracing and pipe insulation. |
| 2/19/2002 | Engine expansion joint inspection | |
| 2/19/2002 | Compressor # 1 problems | Unloader repairs and gauge replaced. |
| 2/22/2002 | Computer problems | Monitor replaced |
| 3/1/2002 | Halon fire protection system replaced with inergen system | |
| 3/5/2002 | Lube oil problems | Changed demister filter |
| 3/11/2002 | Lube oil problems | Secure guard on lube pump motor |
| 3/18/2002 | DC ground | Ground on DC libe pump # 2 |
| 3/21/2002 | DCS Logic changes | EGT mod's |
| 3/22/2002 | DC ground | Control relay in charger |
| 4/4/2002 | Fuel system trouble | Pump # 1 new shaft and impellar |
| 4/8/2002 | GGA failed start | Loue failure on first try |
| 4/12/2002 | Lube system trouble | Failed control relay |
| 4/15/2002 | Lube oil problems | Demister failure due to faulty control relay |
| 4/18/2002 | Lube oil repairs | Repairs to Demister and evaporator |
| 4/22/2002 | GGA failed start | Incomplete sequence |
| 4/23/2002 | Lube oil ststem problems | System not shutting down on GT stop. |
| 4/24/2002 | Compressor problems | New breaker installed |
| 4/26/2002 | Compressor problems | Unloader failure |
| 4/29/2002 | Compressor problems | Oil level switch problem |
| 5/1/2002 | Compressor problems | Unloader failure |
| 5/6/2002 | GGA failed start | Incomplete sequence |
| 5/8/2002 | Generator trip | TRTD failure |
| 5/9/2002 | Site assessment | Begin of site assessment foi oil contamination |
| 5/14/2002 | GGA & GGB louvers | Contractor installing louvers |
| 5/16/2002 | Lube oil problems | Oil leak in jacking pump |
| 6/4/2002 | GGA failed start | Incomplete sequence |
| 6/6/2002 | Fuel system repairs | Repairs made in off-loading area |
| 6/12/2002 | Air compressors replaced | |
| 6/18/2002 | Installed heat tracing cable on GGB | |
| 6/28/2002 | AVR faullt alarm | Reset, no problem found |
| 7/15/2002 | GGA failed start | EGT Alarm |
| 7/16/2002 | GGA failed start | EGT Alarm |
| 7/16/2002 | Lube oil System alarm | High Temp alarm |
| 7/16/2002 | GGA trip | Clutch malfunction |
| 7/17/2002 | Genrator high temp alarm | Glycol system trouble |
| 8/6/2002 | Lube oil system trouble | Demister louver repaired |
| 8/12/2002 | GGA Exhaust stack | Repairs |
| 8/14/2002 | GGA Expansion joint | Repairs |
| 8/16/2002 | Replaced computer monitor | |
| 8/20/2002 | GGA Repairs | Replaced bottom deflector ring |
| 9/3/2002 | GGB Exhaust stack repairs started | |
| 9/6/2002 | GGB expansion joint repairs started | |
| 9/23/2002 | GGA install fire louvers | |
| 9/24/2002 | GGB install fire louvers | |
| 9/27/2002 | Unit controls | Work on control boards |
| 9/30/2002 | Generator Filters replaced | |
| 10/3/2002 | GGA Inspection | Entry guide vanes inspected |
| 10/30/2002 | Speed switch failure alarm | DCS card failure |
| 11/8/2002 | GGA failed start | |
| 11/8/2002 | Generator showing 75 rpm at stop | control card failure |
| 11/19/2002 | GGB fuel leak | failed Jordan valve |
| 12/2/2002 | Jacking pumps cutting in and out | DCS control card failure |
| 12/6/2002 | DCS control problem with speed | Card failure |

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|---|---|---|
| 12/13/2002 | N4 speed awitch repairs | |
| 1/19/2005 | Cooling system | replaced float switch in glycol tank |
| 1/20/2005 | Fuel leak | Leak on main fuel filters |
| 1/24/2005 | GGA Failed start | Incomplete sequence on first attempt |
| 1/26/2005 | Air syatem trouble | Pressure switches repaired |
| 12/28/2005 | DC Ground | Ground on standby diesel |
| 2/7/2005 | Cooling system | Glycol conditioner added |
| 2/8/2005 | Cooling system | Glycol level switch repaired |
| 2/23/2005 | Air system trouble | Air line frozen |
| 3/1/2005 | Fuel system trouble | Calibrate fuel gauge |
| 3/9/2005 | Start fail | No ready lights |
| 3/31/2005 | Ready lights out | Battery ground |
| 4/11/2005 | Asbestos site assessment | |
| 4/12/2005 | Generator trouble | Excitor trouble |
| 4/22/2005 | Replaced Brg # 3 vibration pickup | |
| 5/2/2005 | Failed start | Vibration alarm |
| 5/3/2005 | Cooling system trouble | Glycol Fan # 2 noisy bearing |
| 5/17/2005 | T5 Rad fan repairs | |
| 5/19/2005 | GGB Snow Doors | Repair grease lines |
| 5/26/2005 | Fuel system trouble | Varec gauge calibrated |
| 3/30/2005 | Air Dryer and GGB snow doors repaired | |
| 6/7/2005 | Installed air conditioning unit | |
| 6/8/2005 | Standby diesel fuel tank replaced | |
| 6/9/2005 | Fuel leak | Identified fuel in ground between fuel forwarding building and unit. |
| 6/13/2005 | Unit available in emergency only | Has to be personal on site due to fuel leak |
| 6/15/2005 | GGB unavailable | Failed snow doors |
| 6/23/2005 | Control cables | Had to be relocated due to fuel lines replace |
| 6/28/2005 | GGB Snow doors | repairs to oil lines to snow doors |
| 7/4/2005 | Control building roof repairs by contractor | |
| 7/27/2005 | Fuel System | Contractor started installation of motorized fuel valves |
| 8/4/2005 | Fuel system laeks | Contractor completed replacing fuel lines between fuel forwarding building and units as well a sump drain lines as a result of fuel leak |
| 8/4/2005 | GGA & GGB Inspections | Hot end inspections completed |
| 8/10/2005 | Logic changes for motorized fuel valve | |
| 8/11/2005 | GGB EGT problems | Fuel nozzels checked and logic changes |
| 8/12/2005 | GGB failed start | Fuel nozzel leaks. GGB unavailable thru weekend. Replaced flex line |
| 8/15/2005 | GGB EGT trip | |
| 8/16/2005 | GGB EGT | interchanged nozzels 6 & 8 |
| 8/17/2005 | GGB EGT | Interchanged nozzels from A to B and swapped thermocouples. No success |
| 8/19/2005 | GGB Logic | Breaker must be open in order to start GGB |
| 8/22/2005 | Field ground alarm | |
| 8/23/2005 | Generator stator filter alarm | Field brush connection broken |
| 8/23/2005 | Generator Field | Repairs to brush connection on alternator |
| 8/29/2005 | GGA EGT trip | GGA clutch malfunctioned on shutdown as well |
| 8/31/2005 | GGB EGT trip | Two attempts |
| 9/2/2005 | GGB EGT trip | EGT trip on 3 attempts |
| 9/2/2005 | GGA Clutch failued | Suspected proximity switch |
| 9/19/2005 | GGA Clutch Sticking | |
| 9/19/2005 | GGB EGT | Nozzels interchanged and changes to logic |
| 9/20/2005 | GGB EGT | Logic changes and repairs to nozzel fuel leak |
| 9/21/2005 | GGB EGT Trip at 18 Mw | |
| 9/27/2005 | GGA failed start | Incomplete sequence. Started on 3rd attempt |
| 9/15/2005 | Multiple alarms | Lightning strike. Vibration relan and anunciator cards damaged |
| 11/10/2005 | Sump level logic modified | |
| 11/15/2005 | GGB EGT | Nozzels removed |
| 11/16/2005 | GGB EGT | Rolls Wood and ABB rep's on site for inspection. Fuel leak on startup |
| 11/17/2005 | Unit controls DC ground | GGB Tested to 18 mw where EGT tripped |
| 11/21/2005 | GGB Snow doors | Air leak |
| 11/23/2005 | GGA Vibration Alarm | Alarmed on startup, reset okay |
| 12/15/2005 | Fuel leak | Failed safety valve in fuel forwarding building. All 3 valves replaced. |
| 12/20/2005 | GGB Fuel | Jordan valve replaced |

# Major Mechanical Projects Completed Since 1980 - Hardwoods

1. Fern Engineering Modifications. Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million. (1988)
2. Redesign of inlet air filtration system for gas engine and generator. (early 1990's)
3. Exhaust stack replacement. Existing interior silencer panel was reused. (1992)
4. Snow door actuation was converted from electric to pneumatic. (mid 1980's)
5. Hardwoods B engine serial # 202223 overhaul. (1993)
6. Air Conditioner, for Gas Turbine Control Room, replaced. (2005)
7. New double walled fuel tank for Diesel Gen. (2005)
8. Diesel Gen. replaced. (Nov. 2005)
9. New Flow meter for G. T. (2005)
10. Installed motorized valve fuel line by main tank. (2005)
11. Fuel lines for G. T. installed above ground between unit and the fuel forwarding pumphouse. (2005)
12. Battery Bank replaced 2005 and new standby charger. (2005)
13. Installed new core in Heat Exchanger for MLO system. (2003)
14. Installed new expansion joints in stacks. (2004)
15. Repairs to Glycol housing. (2006)
16. Both Air compressors have been replaced.
17. Gas Turbine and Generator Modules Fire Systems Replacement (Inergen): Hardwoods (2002)

Some information on the projects listed above has been included in the **Reports** folder.

There are many other projects that you may wish to have information on. Please review the document titled ***Mechanical Thermal Projects*** contained in this folder.

**NOTE:** Hardwoods Gas Turbine Site projects begin with **108.**

If you would like to have information on any of the projects listed, please submit a request to Andrea MacDonald for this information.

# Hardwoods Civil Engineering Projects

**HWD**

1) Tank Farm upgrades: <1996/97>
   - 1 tank completed removed
   - remaining tank cleaned, weld repairs, paint interior floor
   - new dyke liner throughout (tank was lifted)
   - dykes re-shaped
   - new dyke section (to reduce size of containment area)
   - new piping within tank farm

2) Paint exterior of tanks <2000>

3)

# Gas Turbine Condition Assessment Information - Hardwoods

## Major Projects (Electrical) - Hardwoods

1. Switchgear Upgrades (information contained in budget proposal) Hardwoods – 1998

   The proposed work involved:

   a. Purchase and installation of new main breaker. This breaker will be rated at 3000 Amp with an interrupting capacity of 28 kA. The existing breaker will be assessed for use as a system spare to serve both the Stephenville and Hardwoods site.

   b. Post insulators and insulation coverings on the rigid bus bars will be replaced/upgraded sufficient to re-rate the switchgear to 15 kV class.

2. Battery Bank Replacements: Hardwoods - 2005
   The 125V 900 amp-hour VRLA bank for the Hardwoods Gas Turbine was replaced in 2005. The intention was for the replacement bank to have the same ratings as the previous bank, but we have been unable to confirm this.

3. Rotor Rewinding and Other Associated Repairs: Hardwoods - early 90's
   a. Files cannot currently be located for this job.

4. Brushless Exciter Vibration Issues Hardwoods – 1994
   a. In October of 1994 high frequency vibration signatures were observed on the exciter and 'B' end alternator bearing. It is unclear as to the cause of these vibrations, and what, if any steps were taken to address the situation.

5. Governor Repairs Hardwoods – 1995/1996
   During the 1994 outage very low ramp rates existed and problems were experienced with the governor. Repairs were made to the governor in 1995 and 1996. Governors were calibrated and droops were setup.

6. Voltage Snubbers: Hardwoods
   This was likely a P&C Project.

# Protection and Control Major Projects - Hardwoods

1. Control System Upgrade: 1997. This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).
2. AVR Replacement: 2006. The Brush BAVR was removed and a new ABB AVR was installed. For details, contact Alex Lau at 737-1788. This has not been done at Stephenville yet.
3. Inverter replacement: Hardwoods - Mar. 2006. Inverter failed and was replaced.
4. Miscellaneous. Thermocouple blocks replaced at Hardwoods on 2003. Terminal blocks in junction boxes located around the unit were replaced at Hardwoods a few years ago due to the condition of the original set. Snubbers (free-wheeling diodes) were replaced at Hardwoods. Some had shorted out a year ago. These were for noise reduction.
5. Emergency backup diesel generating units installed: 2005. Diesel Generating Unit #572 including 600V control panel and backup battery charger installed in existing diesel building. The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery charger which ensures the integrity of the 125 Vdc supply to the gas turbine itself during its starting cycle. The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.
6. NOTES:
    a. Vibration Monitoring Systems at both sites are to be replaced by Dec. 2007. This is a 2007 project. The IRD Mechanalysis units are to be replaced but the accelerometers will be retained.
    b. The Operator Console (PCView software, QNX operating system, Xycom industrial PC) at Stephenville experienced a hard-drive failure. Efforts are ongoing to prepare cost for software and hardware upgrade for both sites to prevent extensive loss of local monitoring in the event of PC-related failure. Both consoles are original vintage (i.e. circa 1999).

## Major Mechanical Projects Completed Since 1980 - Stephenville

1. Fern Engineering Modifications. Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million. (1988)
2. Exhaust stack replacement. Snow doors were modified from electric actuation to pneumatic. Total cost $1.2 million. (1989)
3. Stephenville B engine serial # 202224 overhaul. (2000)
4. Gas Turbine and Generator Modules Fire Systems Replacement (Inergen): Stephenville (2002)

Some information on the projects listed above has been included in the **Reports** folder.

There are many other projects that you may wish to have information on. Please review the document titled ***Mechanical Thermal Projects*** contained in this folder.

**NOTE:** Stephenville Gas Turbine Site projects begin with **106.**

If you would like to have information on any of the projects listed, please submit a request to Andrea MacDonald for this information.

# Stephenville Civil Engineering Projects

**SVL**

1) Tank Farm upgrades: <1999,2000>
   - 3 tanks refurbished (interior cleaned, weld repairs, paint floor)
   - inspection of tanks
   - new dyke liner throughout (tank was lifted)
   - dykes re-shaped
   - new granular dyke materials
   - new sump
   - new piping (within tank farm)

2) Paint exterior of tanks <2004>

3) Painted exterior of GT with rubberized coating system. <2006>

# Gas Turbine Condition Assessment Information - Stephenville

## Major Projects (Electrical) - Stephenville

1. Installation of 15kV Metal Enclosed Switchgear Assembly and Bus Duct: Stephenville – 1998

   This entailed the design fabrication, factory testing, supply and delivery of a 15kV Metal Enclosed Switchgear Assembly. Scope included:

   a. Supply, delivery and placing on existing concrete pad an outdoor, walk-in type 15kV metal enclosed switchgear.
   b. All tools, cranks, and other equipment required for normal operation.
   c. Spare parts.
   d. Two sections of 15kV, 3 phase, non-segregated bus duct between the switchgear and the main transformer, and between the switchgear and the generator.
   e. Structural steel supports to support bus duct.

2. Battery Bank Replacements: Stephenville - 2005

   The 125V 900 amp-hour VRLA bank for the Hardwoods Gas Turbine was replaced in 2005. The intention was for the replacement bank to have the same ratings as the previous bank, but we have been unable to confirm this.

   The VRLA bank for the Stephenville Gas Turbine was also replaced, around the same time, but we have been unable to find further details.

# Protection and Control Major Projects - Stephenville

1. Control System Upgrade: Stephenville - 1999. This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).
2. Inverter replacement: Stephenville Feb. 2004. Inverter failed and was replaced.
3. Emergency backup diesel generating units installed: 2005. Diesel Generating Unit #571 including 600V control panel and backup battery chargers installed in new 3.6m x 4.8m building. The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery chargers which ensures the integrity of the 125 Vdc and 250 Vdc supply to the gas turbine during its starting cycle. The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.
4. Miscellaneous. The type J and K thermocouple wire and terminal blocks in various junction boxes were replaced during the controls upgrade ('99) at Stephenville.
5. NOTES:
    a. Vibration Monitoring Systems at both sites are to be replaced by Dec. 2007. This is a 2007 project. The IRD Mechanalysis units are to be replaced but the accelerometers will be retained.
    b. The Operator Console (PCView software, QNX operating system, Xycom industrial PC) at Stephenville experienced a hard-drive failure. Efforts are ongoing to prepare cost for software and hardware upgrade for both sites to prevent extensive loss of local monitoring in the event of PC-related failure. Both consoles are original vintage (i.e. circa 1999).

# APPENDIX 4
# ALBA REPORT – OLYMPUS ENGINES BORESCOPE INSPECTION HARDWOODS AND STEPHENVILLE

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# ALBA REPORT – OLYMPUS ENGINES BORESCOPE INSPECTION HARDWOODS AND STEPHENVILLE

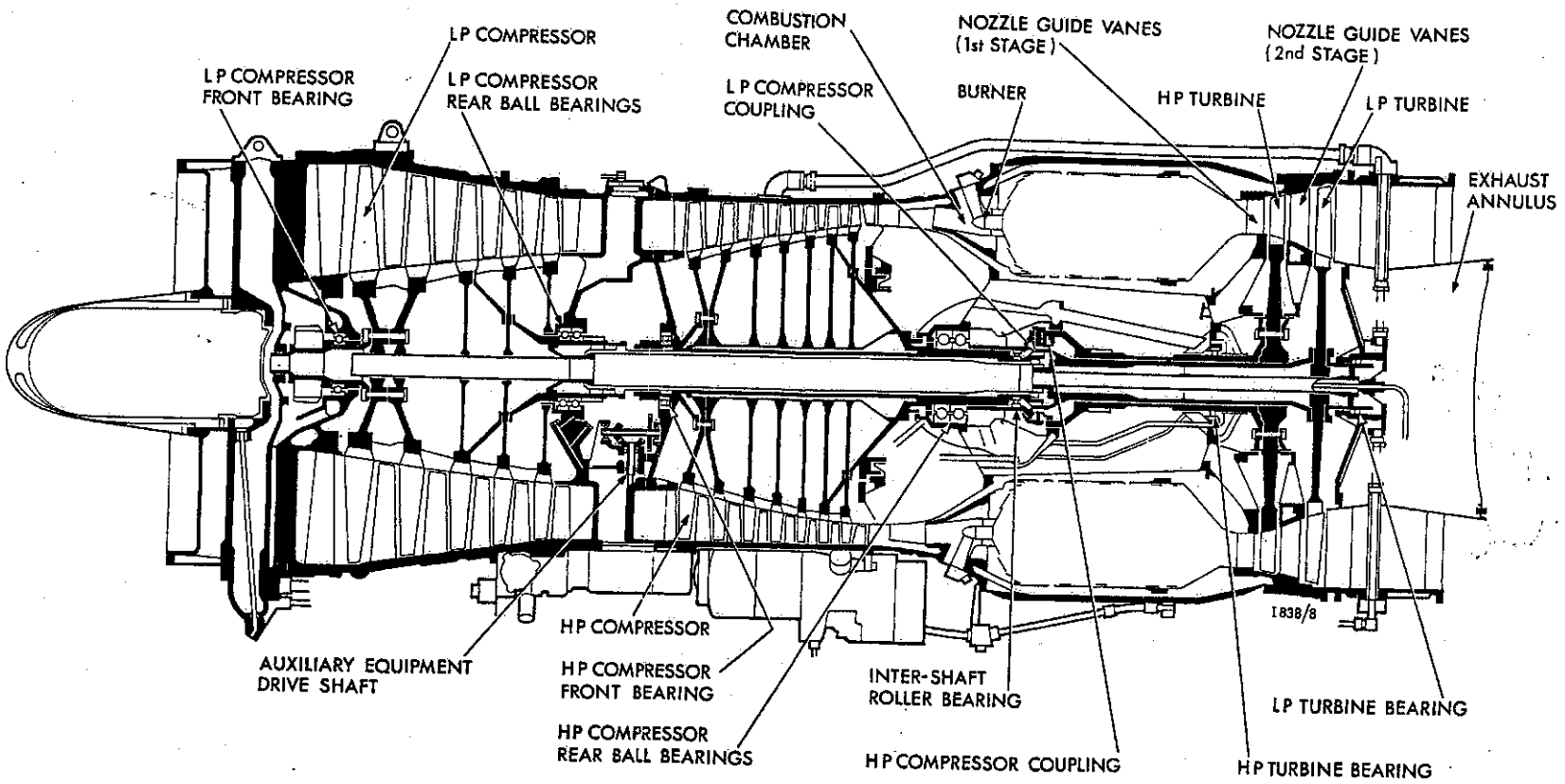



Figure 2-3 Section Through Olympus Gas Generator Newfoundland (Hardwoods) Reissued 20 November 1978

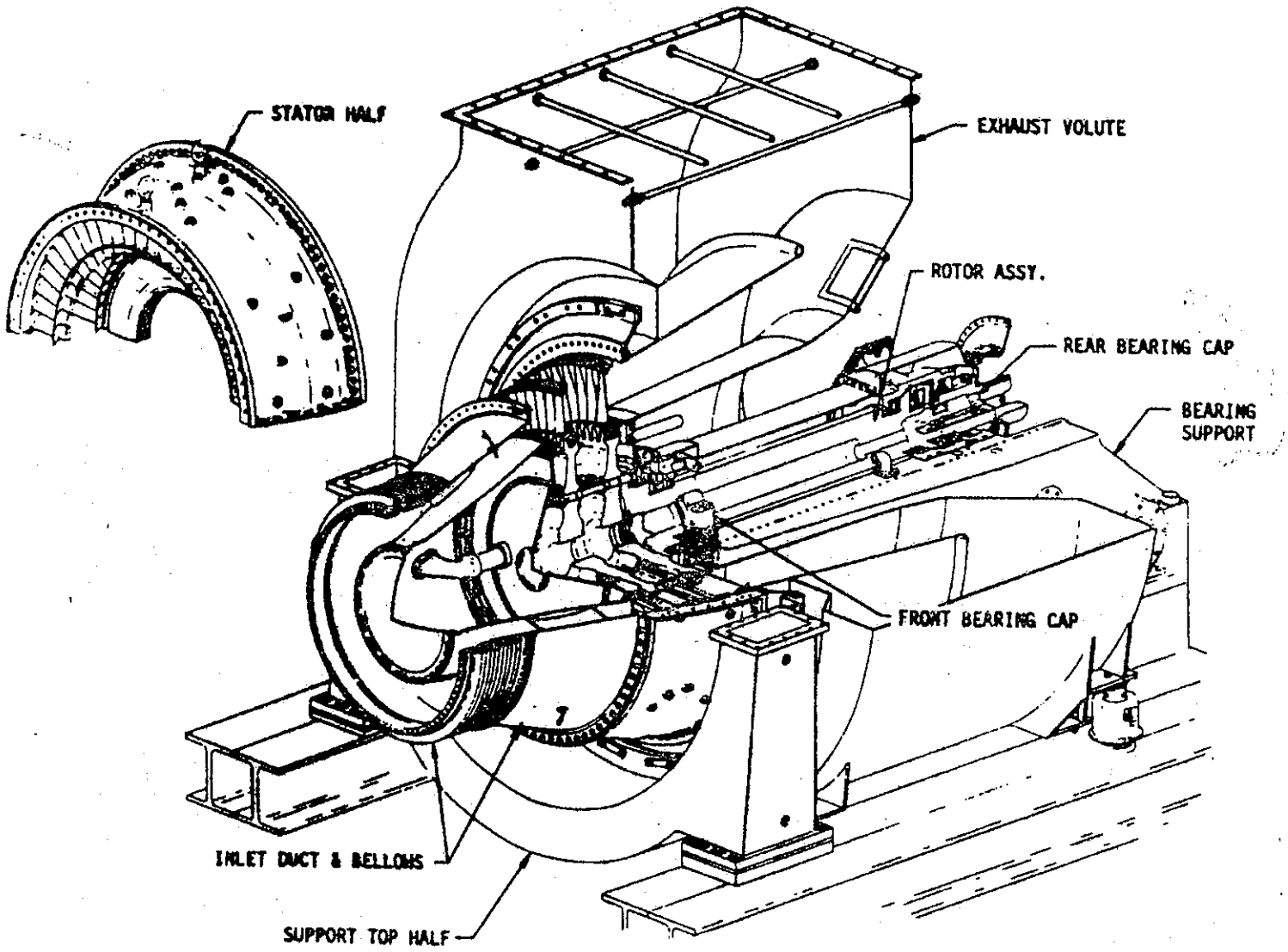



Figure 2-58. CT-2 Power Turbine Major Component Assemblies

# Inspection Report To




# HARDWOODS STEPHENVILLE

## For Olympus Borescope inspection

**Proposal Number: Alba 1457**

**Date: May 30 – 31 2007 Hardwoods & 6-7 June 2007 Stephenville**

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Sales @albapower.co.uk

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ALBA POWER

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***Note:***

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## Introduction

After a successful tender award Alba Power travelled to site to review the units at Hardwoods facility on 30 May 2007.

Alba Power completed the works at site, and due to findings was requested to return to Stephenville for further unit investigation.

This document will detail the steps taken, remedial works completed and future recommendations.

Alba Power would like to take this opportunity to thank the client and staff at Newfoundland Hydro generating site for the assistance and approach to Alba Power, this was greatly appreciated an we look forward to assisting you in the future.

If you do have any questions or queries please do not hesitate to contact us, your contact for this proposal is as follows:

Campbell C Archibald

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# 1 Olympus Borescope Inspection Hardwoods

On Site Personnel- Mr Campbell Archibald and Mr Colin Smith

Date of inspection – 30 - 31 May 2007

**Inspection Review**

On arrival at site a Tool Box review was held with Mr Nelson Seymour. This covered all aspects of site-specific nature including health and safety.

After review it was noted that the client had;

- Removed burners from both units
- Made access to the plenum for compressor inspection

Alba Power then proceeded to the worksite to complete the borescope inspection.

**Workscope Review**

The following are details of the workscope completed at site;

### 1.1.1 Wednesday 30 May 2007

After review Alba Power completed unit A and B borescope inspections.

At the clients request the burners or filters were not inspected or cleaned.

The air intake housing was rectified after it was found that the circlip had moved.

### 1.1.2 Thursday 31 May 2007

Alba Power was requested to return to site to view the start of the units.

Unit B operated correctly at first attempt. Unit A suffered from high deviation, after thermocouple review and burner cleaning the unit operated correctly.

# 2 Borescope Results

As detailed within our workscope above the unit was borescoped throughout and within this report we will detail the sections accordingly.

All images will be provided separately on a CD for client files.

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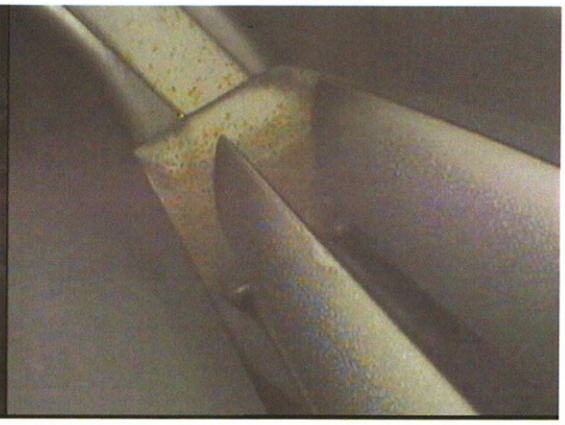
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## Compressor Section Unit A

In general the unit shows signs of corrosion, coating loss and staining due to location. This should be monitored and repaired prior to component degradation.



**Inlet Guide vane corrosion**



**Stage 1 shroud corrosion**



**Stage 5 OGV coating loss HP Compressor entries**

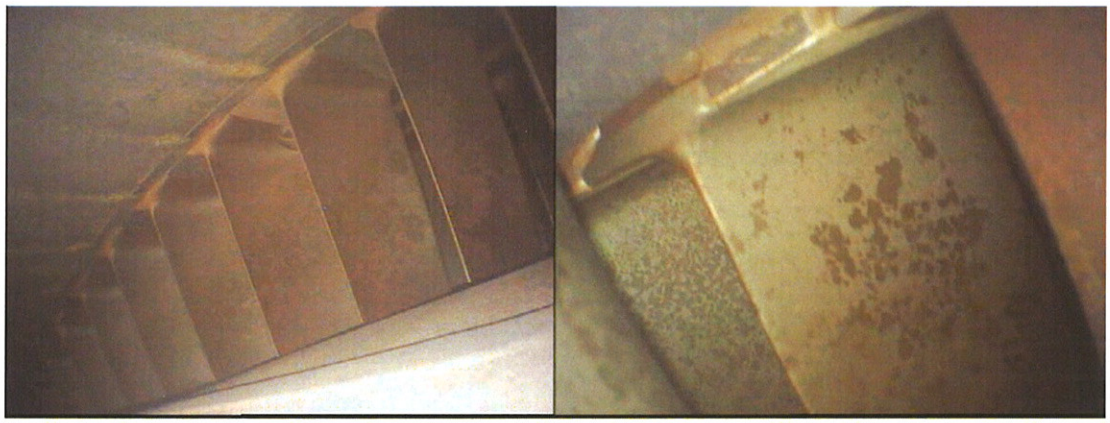
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**HP Compressor corrosion**



**HP Compressor corrosion**

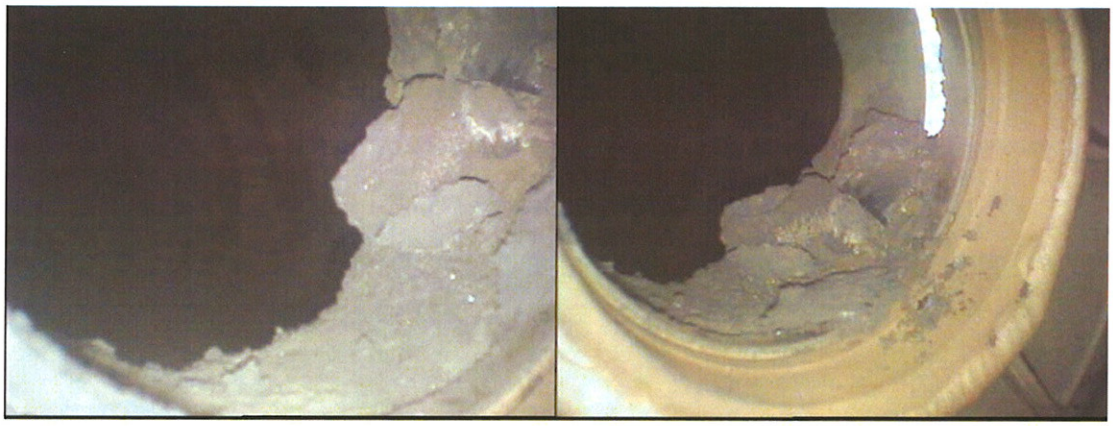
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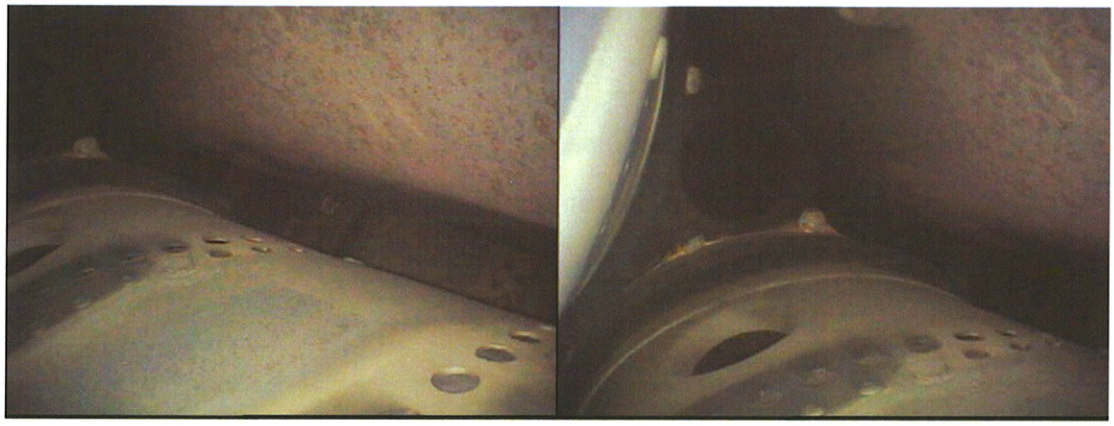
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## Combustion Section Unit A

The combustion cans are badly effected by carbon and have suffered material loss and cracking throughout. These cans should be changed at the earlier opportunity and a regime of waterwash and burner cleaning implemented every 6 months. This would prolong the life of the burners and cans.



**Typically found carbon deposits**



**External view of Combustion cans and clamps**

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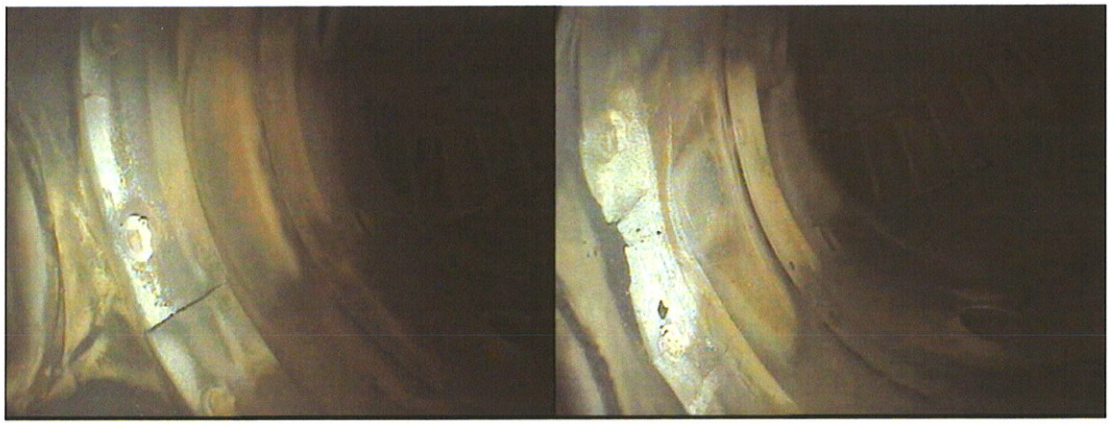
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**Cracking on No 3 Can**



**Material loss on combustion cans**

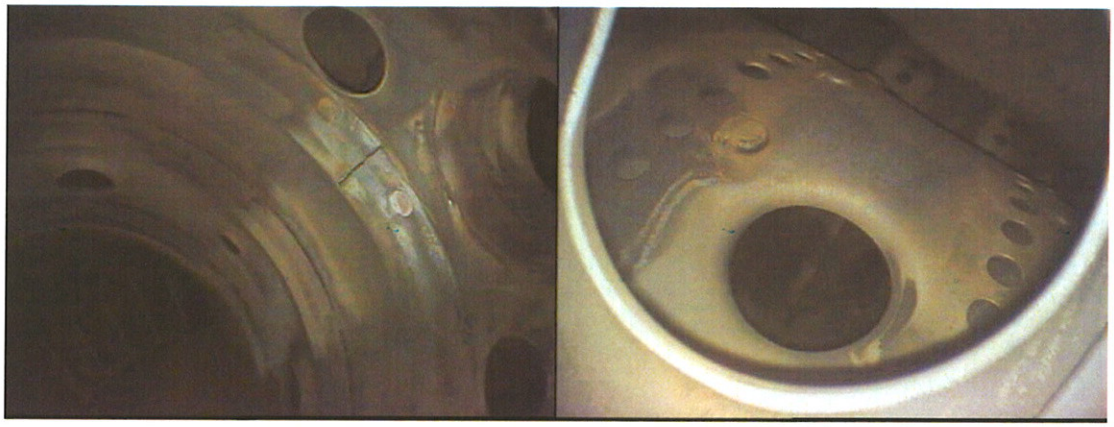


**Cracking of No5 Can** **Material loss of No6 Can**

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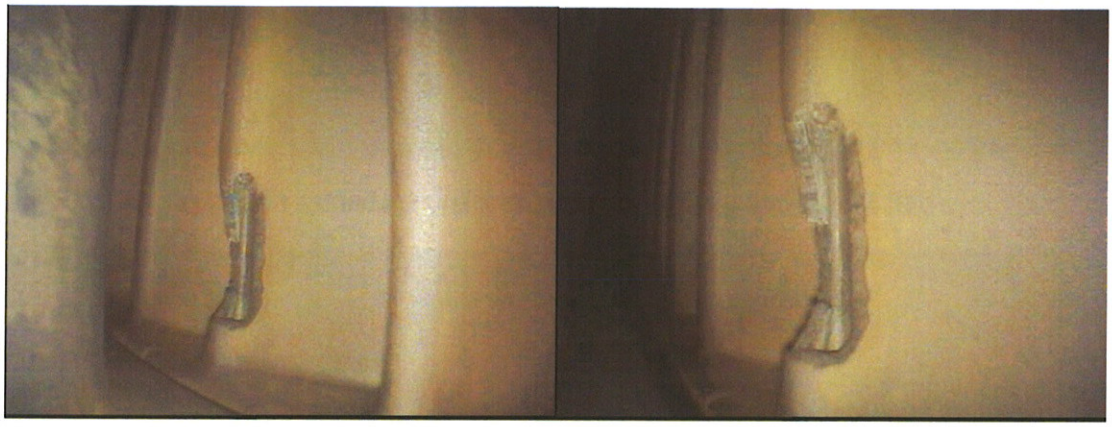
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**Cracking in No7 Can** **External view of No7 Can**

**Turbine Section Unit A**

As can be seen a sizeable portion of 2 blades has been removed through collision or erosion. The remaining blades show sign of coating loss and pitting. Consideration should be given to removing the unit immediately for remedial works. This is currently a safety risk, and at risk of further damaging the unit should the blade fail entirely. (See Alba Power options for repair, overhaul and exchange)

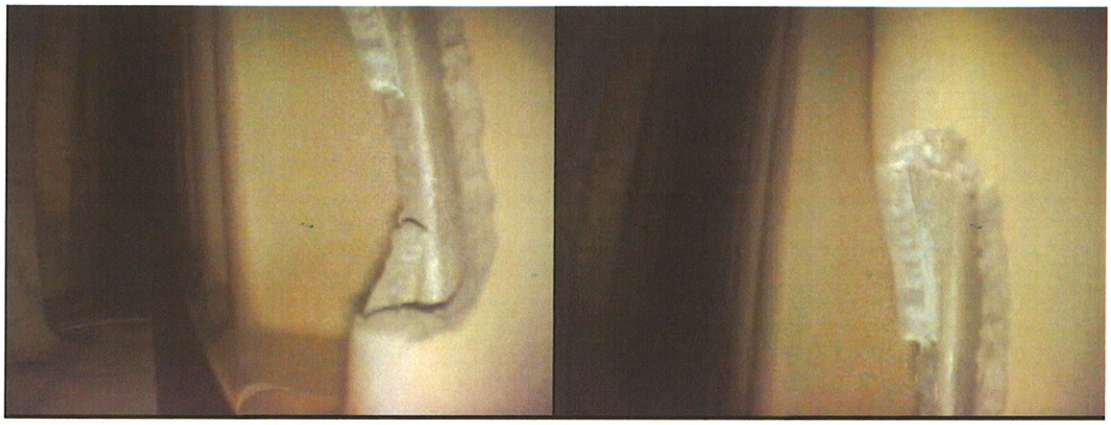


**HP Blade damage, blade found no 1**

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**HP Blade damage, blade found no 1**



**HP Blade damage, blade found no 2 (separated by 4 blades)**

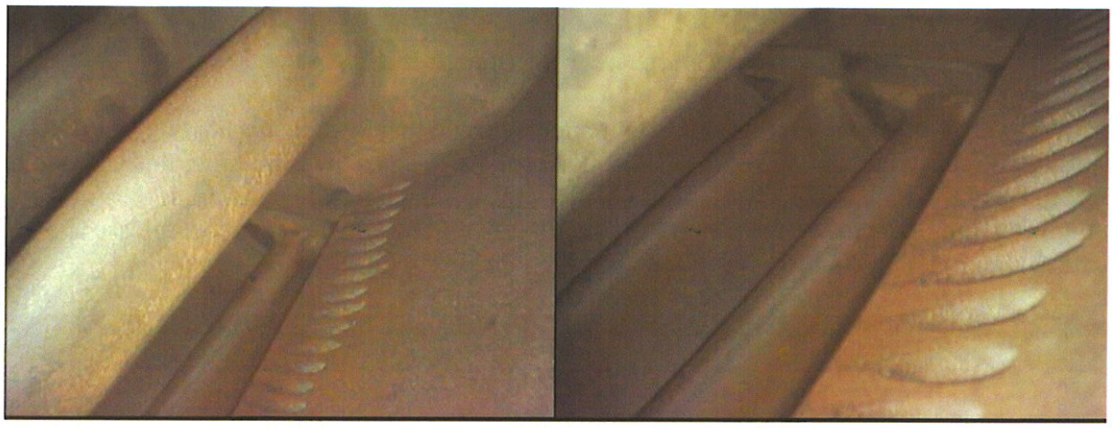


**HP blade damage, No2** **Impact damage on 3rd blade**

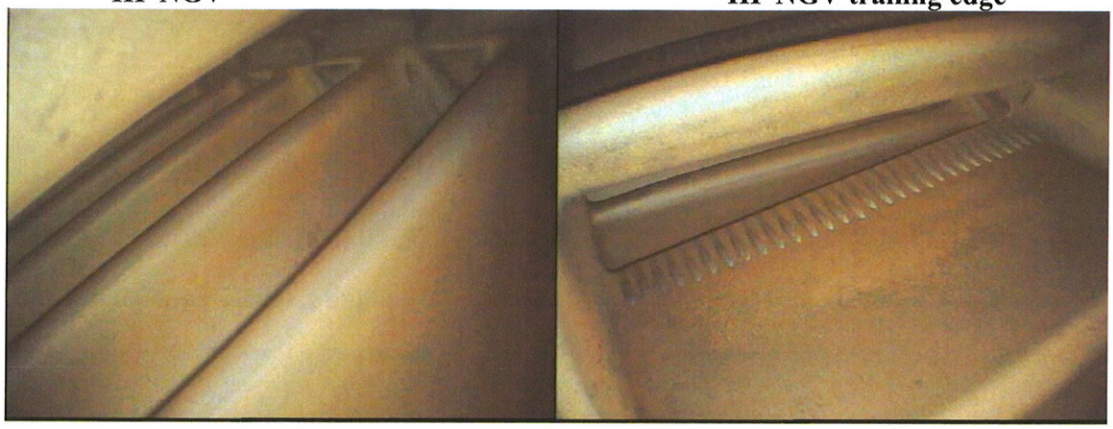
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**HP NGV** **HP NGV trailing edge**



**HP Blade** **HP NGV**



**HP Blade roots** **HP Blade interlock**

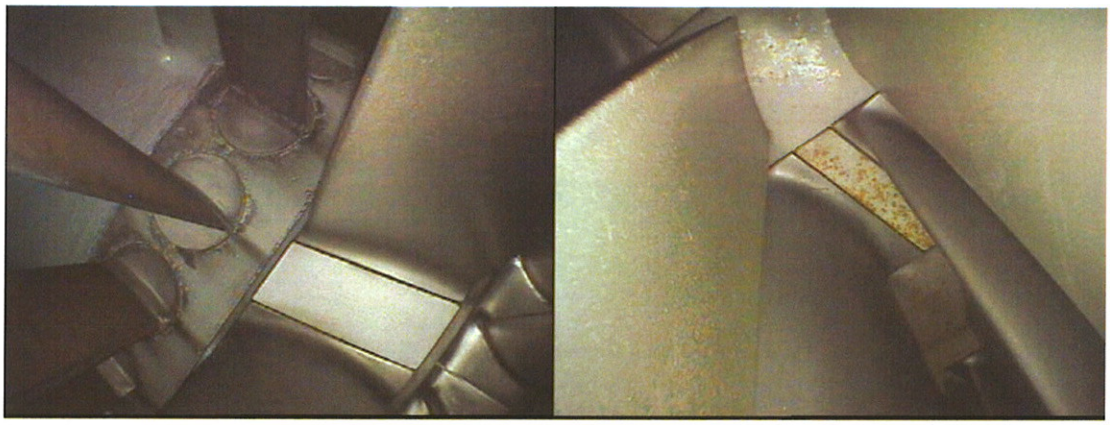
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## Compressor Section Unit B

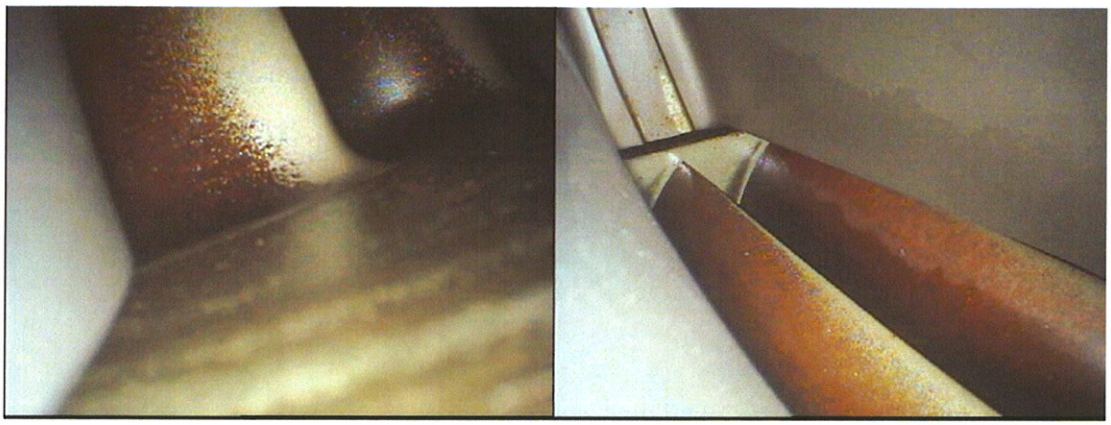
The compressor section on this unit is extremely corroded with extensive coating loss and pitting. It was found that one of the HP compressor stator spacer was missing, this has lead to creeping of the remaining stators. These blades are now in an unsafe position, if they move slightly through operation further spacers and blades will be allowed to move, release and cause major damage to the unit. (Please see Alba Power proposal for onsite repair)



**IGV Corrosion and pitting**



**Stage 1 spacer corrosion**

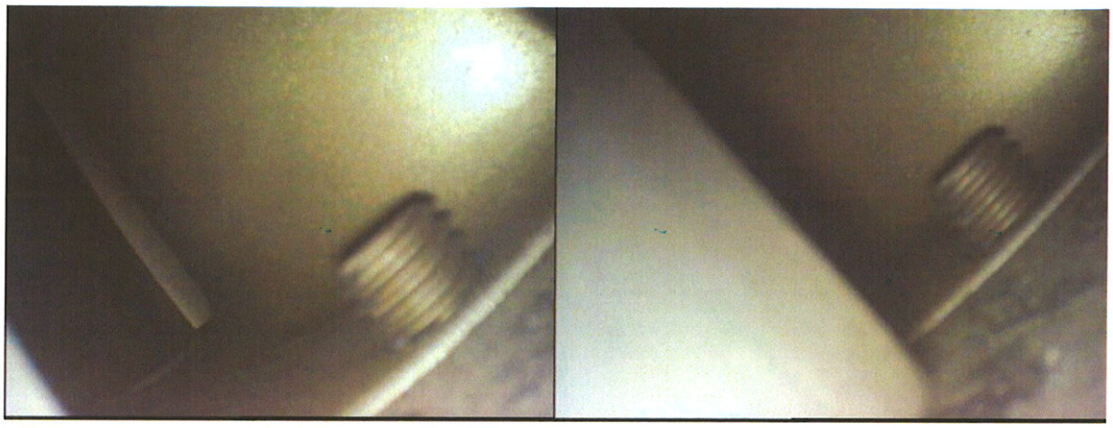


**Coating loss Stage 5**

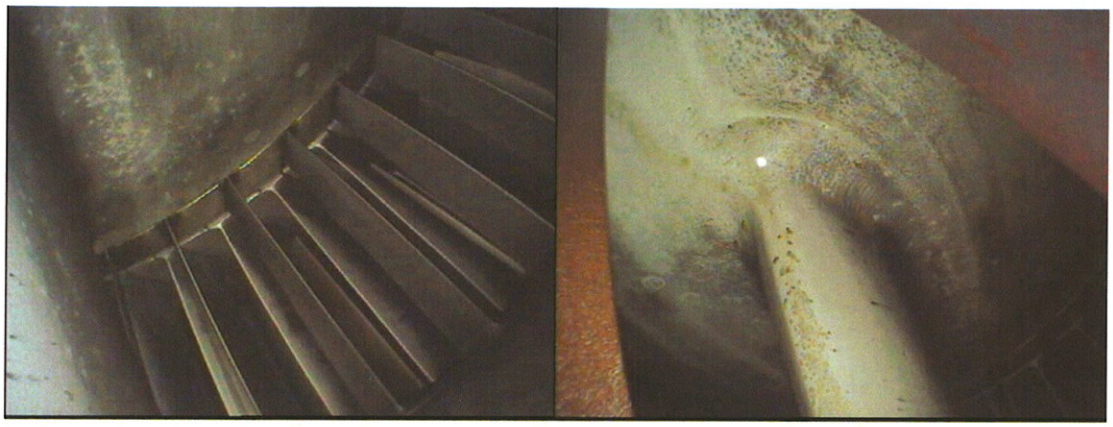
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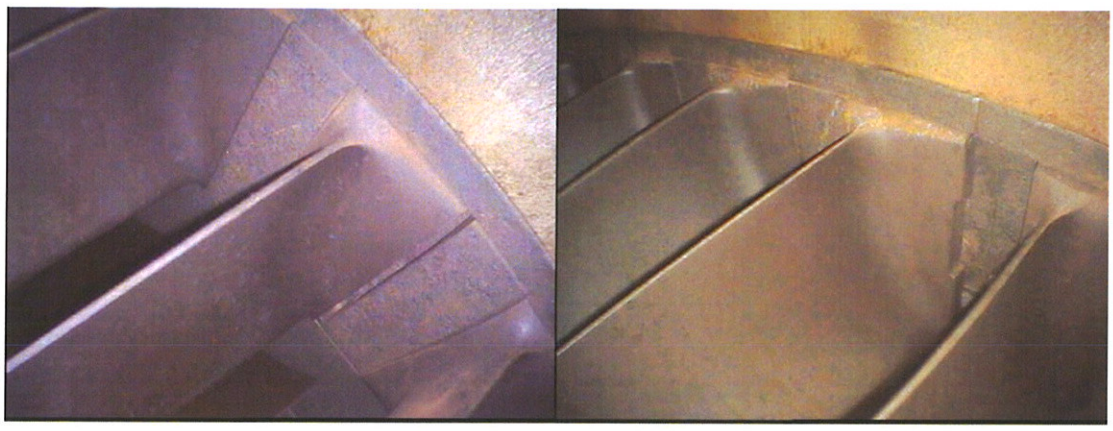
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**Incorrect stud fitment, stage 3**



**HP Compressor entry**



**OGV Stator gap** **missing spacer plate**

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**Gap growth on stator**



**General condition of HP compressor**

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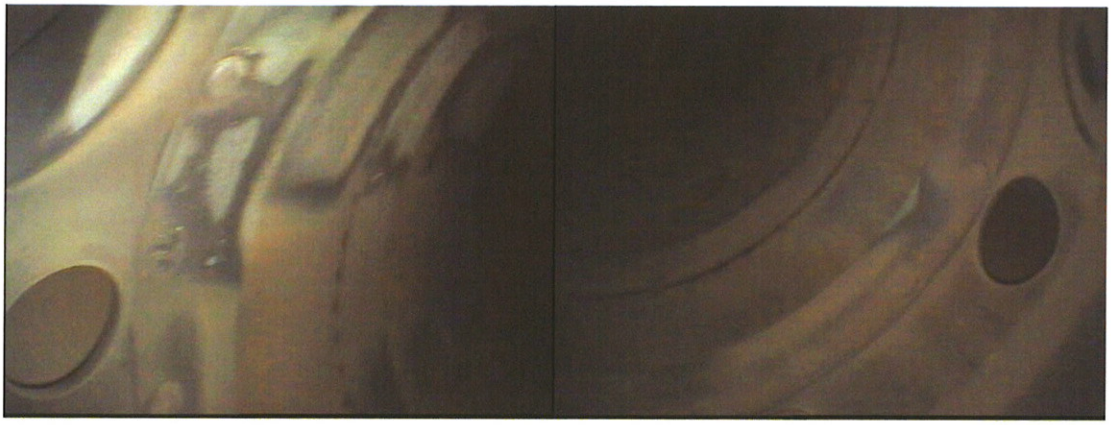
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## Combustion Section Unit B

The combustion second, although heavily affected by carbon, was in good condition and should be monitored yearly through borescope.



**External Combustion can and clamp**

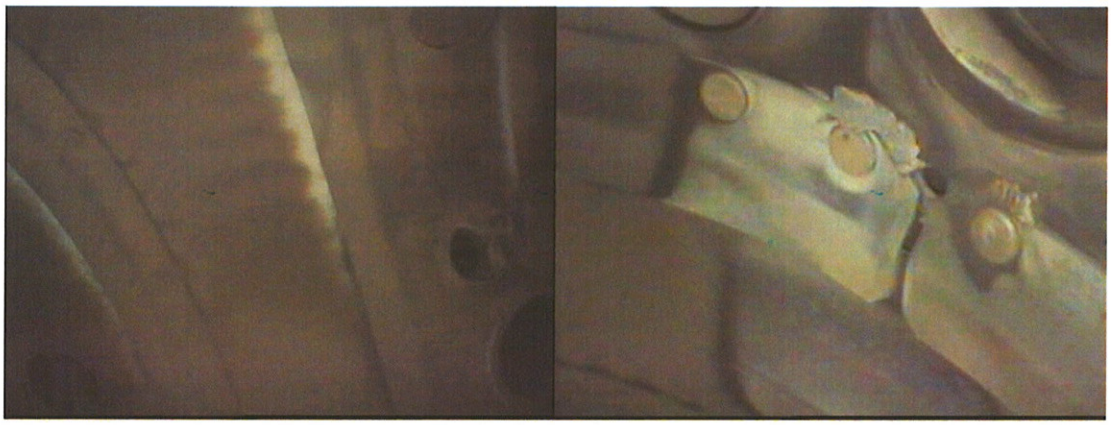


**General combustion chamber condition**

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**Combustion cracking and material loss**

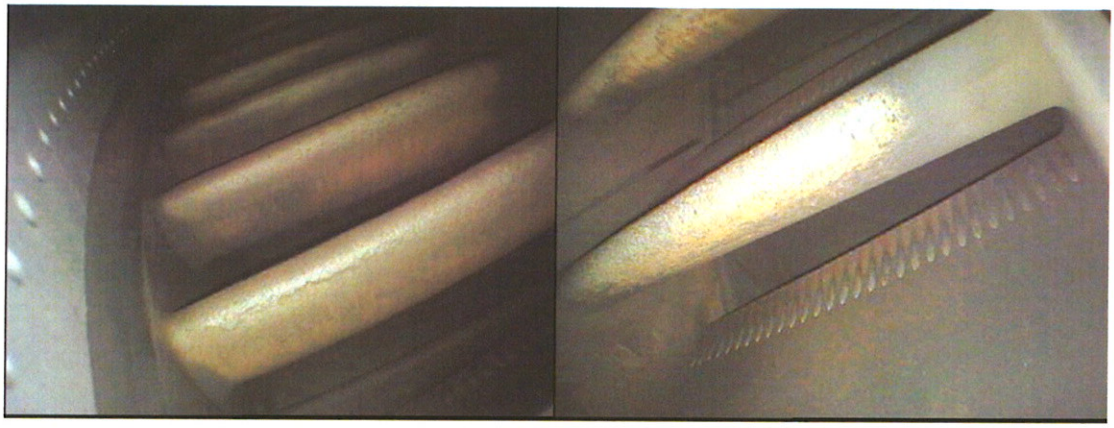
Mill of Monquich
Netherley
ABERDEENSHIRE
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Scotland

ALBA POWER

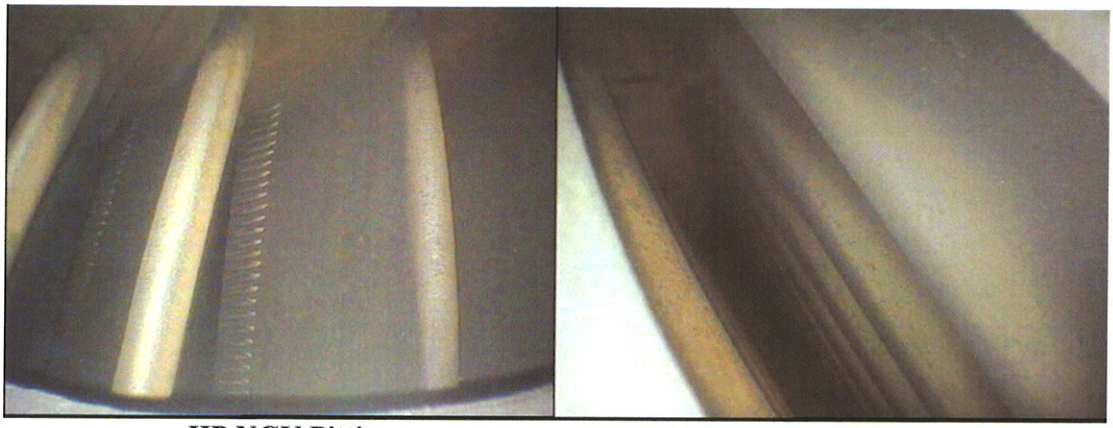
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## Turbine Section Unit B

The turbine section was found to have heavy deposits of carbon, perhaps evidence of fuel pump issues. In the main the unit has coating loss and pitting on the HP NGV's, however this would continue in service through regular yearly monitoring.



**HP NGV coating loss and staining**

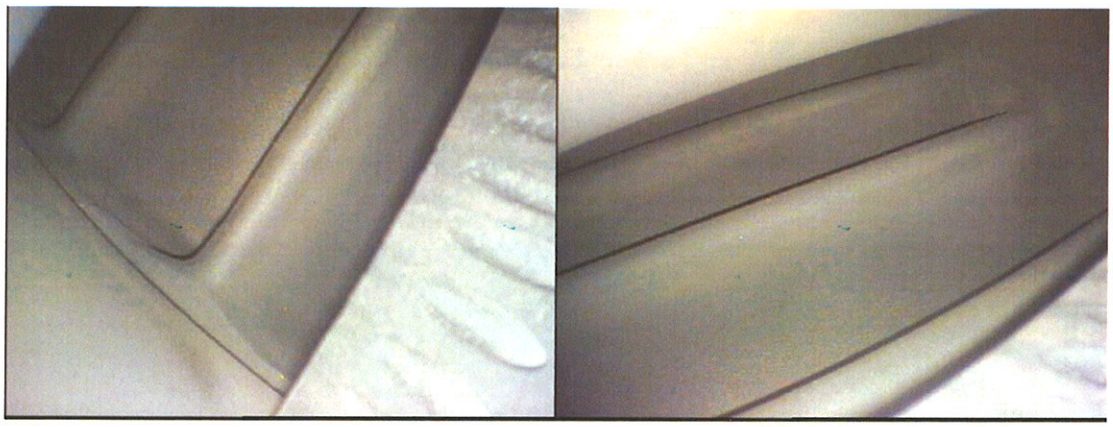


**HP NGV Pitting** **HP blade**

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**HP Blade condition**

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## 3 Olympus Borescope Inspection Stephenville

On Site Personnel- Mr Campbell Archibald and Mr Colin Smith

Date of inspection – 6 – 7 June 2007

**Inspection Review**

On arrival at site a Tool Box review was held with Mr Nelson Seymour. This covered all aspects of site-specific nature including health and safety.

Alba Power then proceeded to the worksite to complete the borescope inspection.

**Workscope Review**

The following are details of the workscope completed at site;

### 3.1.1 Thursday 7 May 2007

After review Alba Power completed unit A and B borescope inspections.

At the clients request the burners or filters were not inspected or cleaned. It was noted that the intake assembly has moved with age, this should be rectified at the earliest opportunity.

Alba Power witnessed a failed start caused by starter motor issues.

## 4 Borescope Results

As detailed within our workscope above the unit was borescoped throughout and within this report we will detail the sections accordingly.

All images will be provided separately on a CD for client files.

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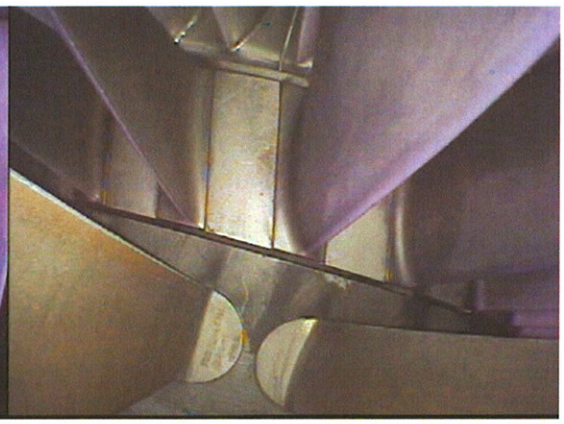
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## Compressor Section Unit A

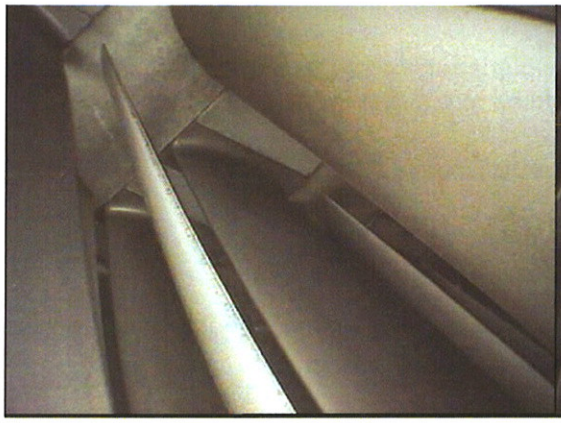
The unit was generally in clean condition with some minor corrosion and pitting. The rear of the HP compressor does show signs of corrosion.



**Inlet Guide vanes**



**Inlet guide vane journal**



**Stage 1 blades**

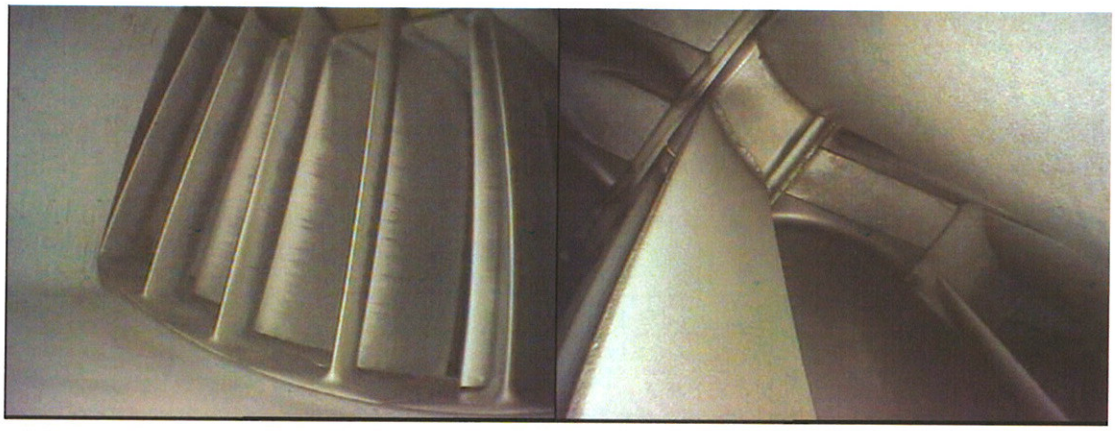


**Stage 5 stator**

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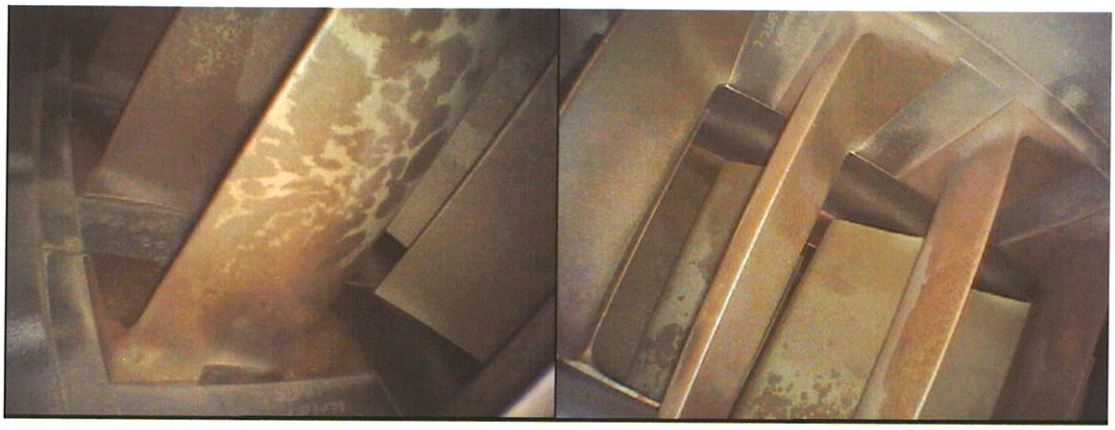
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**HP compressor stage 1**

**Stage 1 LP stator pitting**



**HP compressor corrosion**

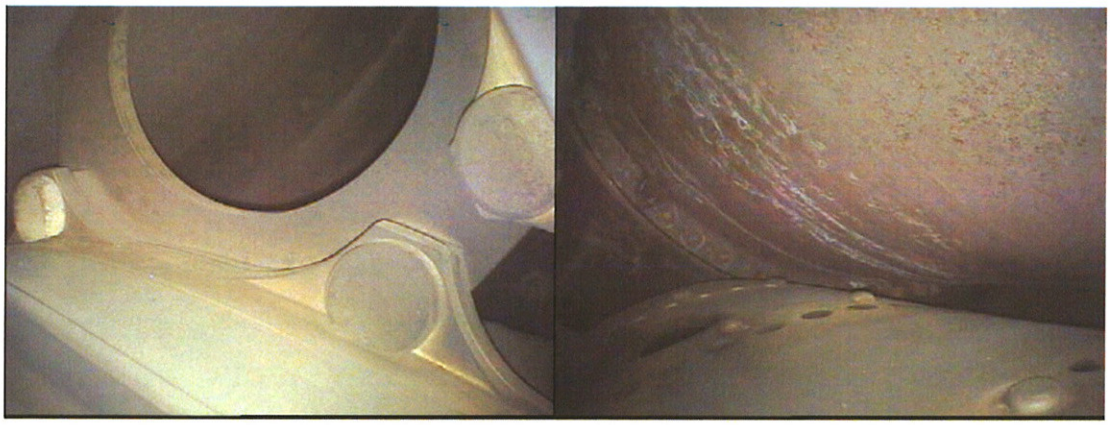
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## Combustion Section Unit A

The unit showed signs of coating loss with No5 can show excessive liquid staining. This could be a sign of burner wear or fuel pump issues.



**Combustion can external images**

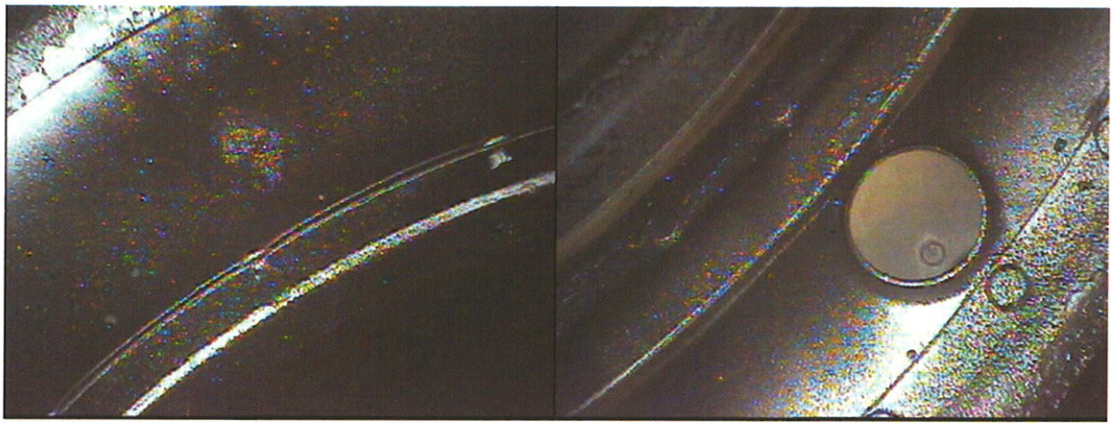


**Combustion can coating loss**

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**No 5 Staining**

**Turbine Section Unit A**

The turbine section showed signs of excessive pitting and coking, again a sign of incorrect fuel flows. It would be advisable to plan for full inspection and recoating of the NGV's and blades before the capital equipment is beyond repair.



**HP NGV,s with pitting and coking**

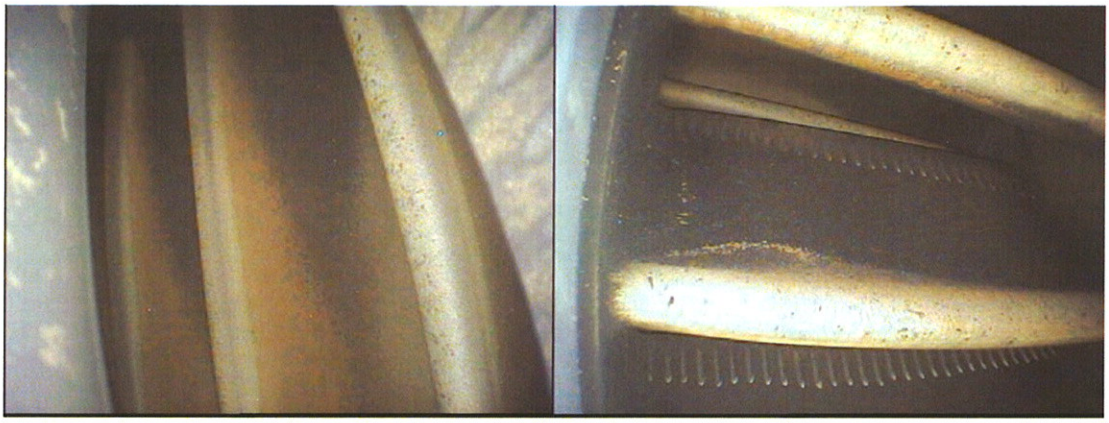
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**HP Turbine blade locking and pitting**



**HP blade and NGV coating loss and excessive**



**Excessive coating loss on HP NGV**

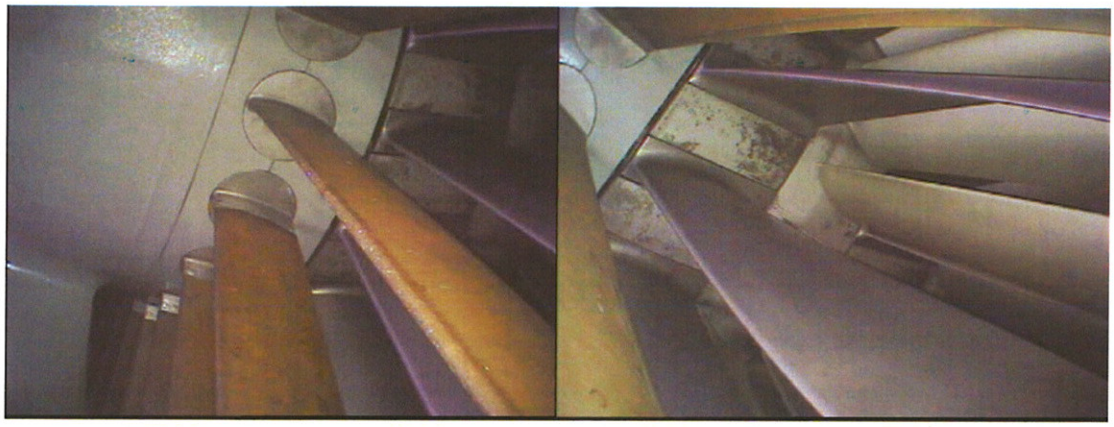
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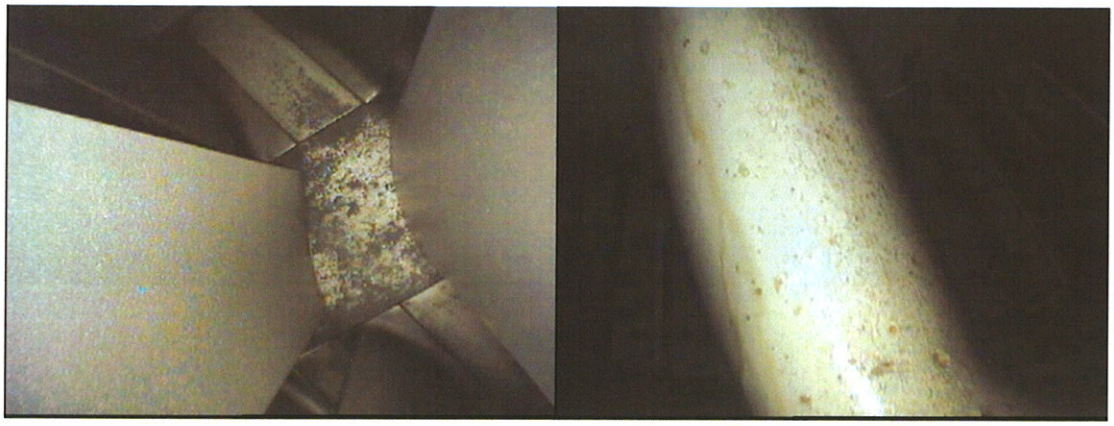
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## Compressor Section Unit B

The compressor shows sign of excessive pitting, particularly in the early stages and Intermediate casing. This should be monitored at next inspection.



**IGV bushes and casing**

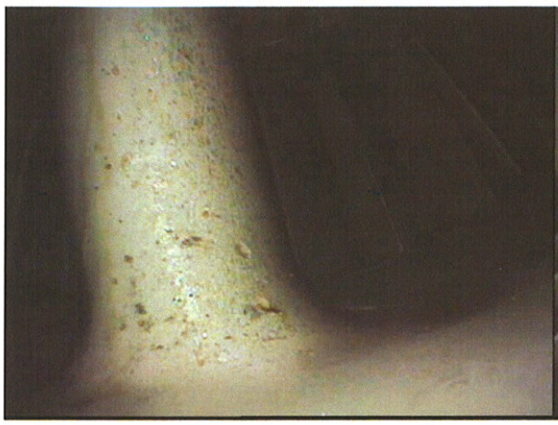


**Stage 1 corrosion** **Intermediate case pitting**

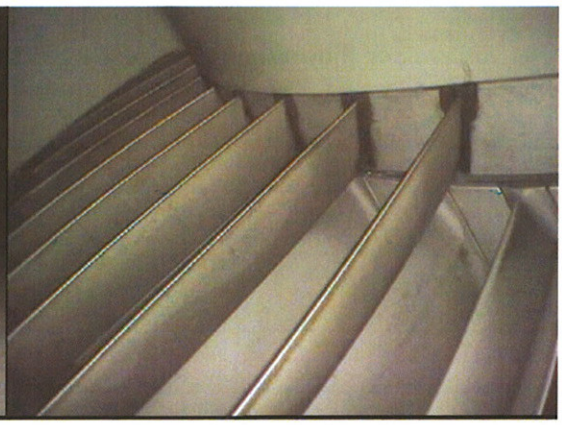
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**Intermediate case pitting**



**HP compressor entry**





**HP compressor exit**

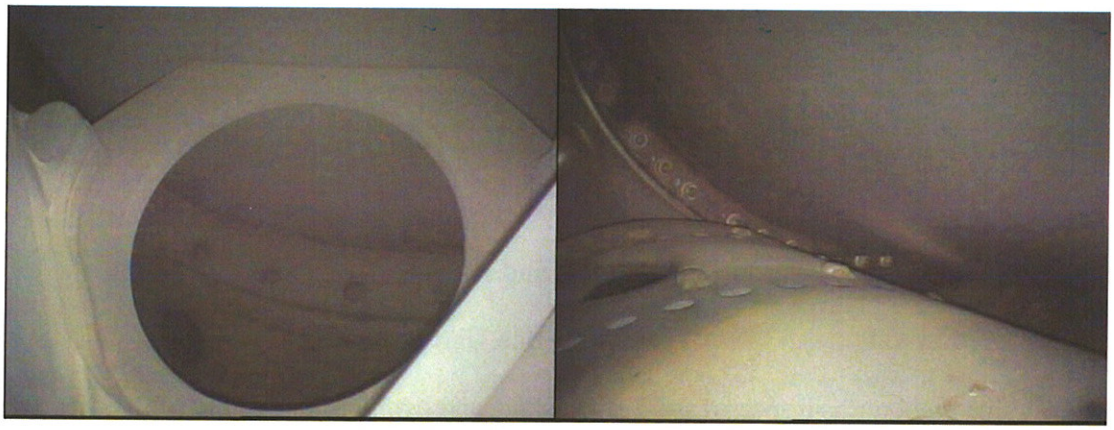
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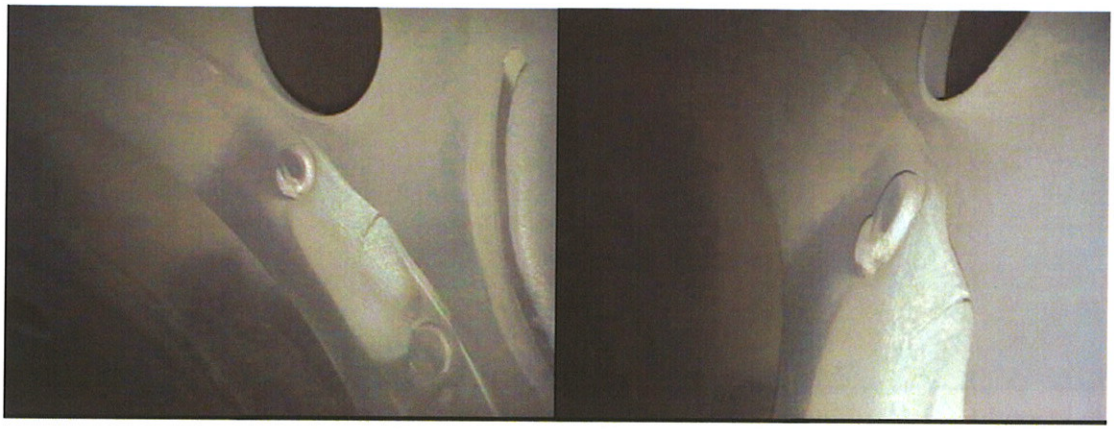
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## Combustion Section Unit B

The combustion area was generally in good condition with the exception of the No5 position, which has a large crack and material loss.



**External area of combustion can**



**No 5 cracking**

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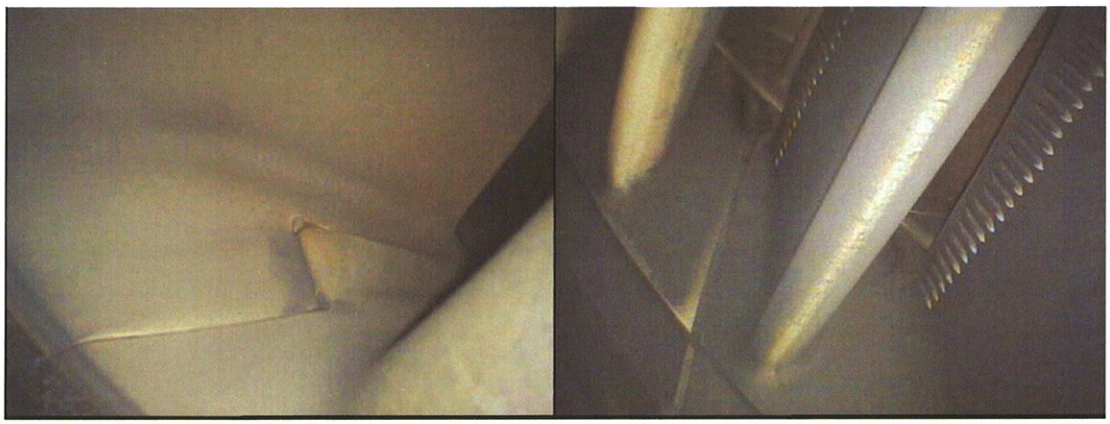
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**Coating loss and staining**

**Turbine Section Unit B**

The turbine section was inspected and heavy coking and light cracking of the HP NGV's were found. This should be monitored for growth at next inspection period.



**HP blade interlocks** **HP NGV leading edge**

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**HP NGV damage** **HP blade leading edge**



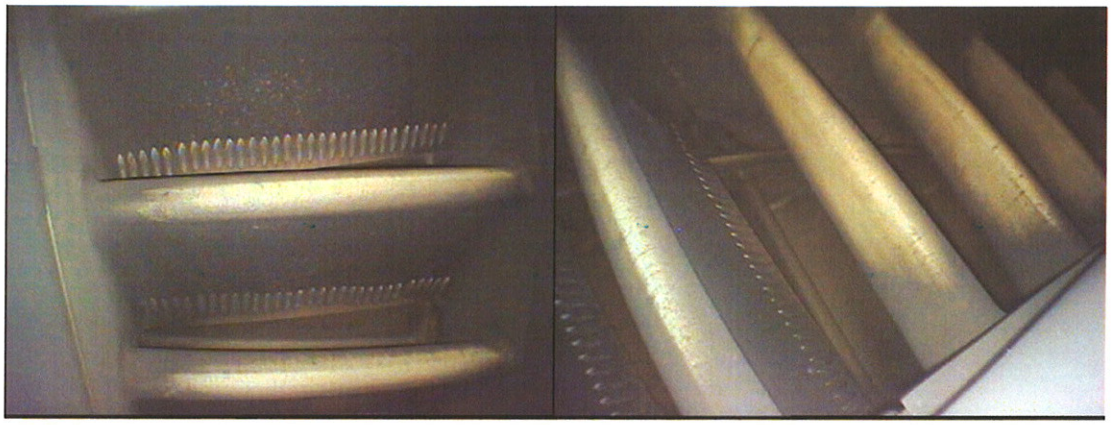
**HP NGV's**



**HP NGV trailing edge scallop**

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**HP NGV coking**

## 5 Additional items / workscope completed

In conjunction and review with the client the following additional scopes of work were completed and will be charged separately.

- Return travel and manpower to Stephenville inspection
- Return to Holyrood for start procedures

In addition Alba Power noted the following requirements that can be supplied or quoted on request;

- New Fuel rail supply for Holyrood
- Transition ducting for Holyrood
- Ignitors for all sites

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## 6 Conclusions / Recommendations

As can be seen by the borescope images Alba Power unveiled significant damage to both units at Hardwoods. The unit at Stephenville should be inspected regularly to measure the growth of the highlighted items for strategic planning of future repair requirements. This unit would also benefit from compressor washing as well as inspection of the fuel system.

Alba Power would recommend the following options at Hardwoods, all of which Alba Power will supply a quote for separately;

- Unit A
  - This unit should be removed from service as soon as possible, at present this is a health and safety risk as well as a risk to the parent material. The options for this unit are;
    - Exchange unit with Alba Power serviceable unit
    - Return unit to Alba Power for light repair concentrating on;
      - Turbine blade replacement
      - Combustion can repair
      - Inspection of all other components, rebuild test and return
    - Full overhaul at Alba Power

- Unit B
  - This unit has a significant item missing with the remainder of the stators creeping with risk of further loss and catastrophic failure. The unit should have the following works completed;
    - On site top half lift and replacement parts fitted

Alba Power believes we can assist greatly and will quote accordingly. Alba Power will apply best practise to ensure the client has a fit for purpose repair while returning the unit to the client as swiftly as possible. As discussed we can complete these options immediately on request.

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## 7 Timesheets

**ALBA POWER LTD**

ALBA POWER

Payroll Daily Timesheet

Week ending :- 25 JUNE 2007 Employee name :- C. ARCHIBALD

| Day | Date | Location | Onshore / Offshore | Normal Time | O/Time x 1 1/2 | O/Time x 2 | Bonus | Description |
|---|---|---|---|---|---|---|---|---|
| Sun | | | | | | | | |
| Mon | | | | | | | | |
| Tue | | | | | | | | |
| Wed | 30 MAY 07. | HARD-WOOD NFM. | 11 | | | | | OLYMPUS BORESCOPE. |
| Thu | 31 MAY | " | | | | | | UNIT ROTOR START. |
| Fri | | | | | | | | |
| Sat | | | | | | | | |

Employee Signature :

Approved: Mike Simpson

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## ALBA POWER LTD

ALBA POWER

**Payroll Daily Timesheet**

Week ending :- 9 JUNE

Employee name :- C. ARCHIBALD

| Day | Date | Location | Offshore | Normal Time | OTime x 1 1/2 | OTime x 2 | Bonus | Description |
|---|---|---|---|---|---|---|---|---|
| Sun | | | | | | | | |
| Mon | | | | | | | | |
| Tue | | | | | | | | |
| Wed | 6 JUNE 2007. | STEPHENVILLE. | | 12 | | | | TRAVEL TO SITE. |
| Thu | 7 JUNE 2007. | STEPHENVILLE | | 10 | | | | ROSELEE PC CRANE |
| Fri | | | | | | | | |
| Sat | | | | | | | | |

Employee Signature : CA

Approved:

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## ALBA POWER LTD

ALBA POWER

Payroll Daily Timesheet

Week ending :- 2 JUNE 2007 Employee name :- C. SMITH

| Day | Date | Location | Onshore | Offshore | Normal Time | O'Time @ x 1.5 | O'Time @ x 2 | Description |
|---|---|---|---|---|---|---|---|---|
| Sun | | | | | | | | |
| Mon | | | | | | | | |
| Tue | | | | | | | | |
| Wed | 30 May 07 | HARDWOODS. NFM. | 11 | | | | | OLYMPUS BREAKAGE. |
| Thu | 31 May 07 | 11 | | | | | | UNIT FOREMAN STAGE. |
| Fri | | | | | | | | |
| Sat | | | | | | | | |
| | | TOTALS: | | | | | | |

Employee Signature :

Approved:

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## ALBA POWER LTD

ALBA POWER

Payroll Daily Timesheet

Week ending :- 4 June

Employee name :- Colin Smith

| Day | Date | Location | Offshore | Normal Time | OTime x 1 1/2 | O Time x 2 | Bonus | Description |
|---|---|---|---|---|---|---|---|---|
| Sun | | | | | | | | |
| Mon | | | | | | | | |
| Tue | | | | | | | | |
| Wed | 6 June 2007 | Stephenville | | 12 | | | | Travel to Site |
| Thu | 7 June 2007 | Stephenville | | 10 | | | | Remove & Replace Cylinder |
| Fri | | | | | | | | |
| Sat | | | | | | | | |
| | | | | | | | | |

Employee Signature :

Approved:

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# 8 Future personnel requirements

Human Resources and Social Development Canada | Ressources humaines et Développement social Canada — Canada

**Foreign Worker Quick Links:**

Foreign Worker Home Page [Go]

Employing foreign workers can be an essential part of a company's business strategy. Foreign workers can fill labour shortages in Canada and bring new skills and knowledge to help the country's economy grow.

**HIRING STEPS :**

In almost all cases, foreign workers must have a valid work permit to work in Canada. When hiring a foreign worker, you, the employer must generally :

1. Submit an HRSDC Foreign Worker Application for a labour market opinion (LMO) to the Service Canada Centre responsible for your area.

   Before confirming a job offer, HRSDC considers whether :

   - The job offer is genuine;
   - The wages and working conditions are comparable to those offered to Canadians working in the occupation;
   - Employers conducted reasonable efforts to hire or train Canadians for the job;

   **NEW: Hiring Temporary Foreign Workers for Occupations under Pressure**

   In some regions, and depending on the circumstances/time, labour market information may indicate that the demand for labour in certain specific occupations is greater than the available supply. To meet the pressing human resource needs of employers, Human Resources and Social Development Canada (HRSDC) and Service Canada (SC) have developed Regional Lists of Occupations under Pressure. For occupations found on these lists, employers will not be required to undertake lengthy or comprehensive advertising efforts before being eligible to apply to hire a foreign worker.

   For more information, please visit:

   - Hiring Temporary Foreign Workers for Occupations under Pressure
   - News Release

   - The foreign worker is filling a labour shortage;
   - The employment of the foreign worker will directly create new job opportunities or help retain jobs for Canadians;
   - The foreign worker will transfer new skills and knowledge to Canadians; and
   - The hiring of the foreign worker will not affect a labour disputes or the employment of any Canadian worker involved in such a dispute.

   Learn more about the HRSDC LMO assessment criteria, noting that a Quebec Acceptance Certificate (CAQ) issued by the province is also required for jobs in Quebec.

2. Once HRSDC approves the job offer, send a copy of the HRSDC LMO confirmation letter to the foreign worker.

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3. Inform the foreign worker to apply for a work permit from Citizenship and Immigration Canada (CIC).

**Next,** CIC decides whether the foreign worker will get a work permit according to the requirements to work and reside temporarily in Canada.

**SPECIAL CONDITIONS :**

Under the *Immigration and Refugee Protection Act (IRPA)*, there are special cases when employers do not need an HRSDC labour market opinion to hire a foreign worker, and/or the foreign worker may not need a Citizenship and Immigration Canada (CIC) work permit.

- Learn about occupations that are exempt from the HRSDC labour market opinion.
- Learn about occupations that are exempt from the CIC work permit.

Also, please note that special criteria apply for employers hiring foreign workers in some industry sectors and occupations including :

- Academics
- Seasonal Agriculture
- Film and Entertainment
- Information Technology
- Live-in-caregivers
- Pilot Project for Occupations requiring a high school Diploma or Job-specific Training

| LOCATION | ADDRESS | PHONE | FAX |
|---|---|---|---|
| **St. John's** | P.O. Box 8548<br>223 Churchill Avenue<br>Pleasantville<br>St. John's, Newfoundland<br>A1B 3P3 | (709)-772-2982 | (709)-772-6442 |

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# 9 WHSCC approval

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Telephone: (709).778-1000 • Toll Free 1.800.563.9000 • Fax: (709).778-1110 • www.whscc.nf.ca

ASSESSMENT SERVICES DEPARTMENT FAX: 709 778 1110

MAY 29 2007

FAX: 709 536 4104

NEWFOUNDLAND POWER INC
Attn: John Budgell
P O BOX 8910
ST JOHN'S NL A1B 3P6

CERTIFICATE OF CLEARANCE

TO: NEWFOUNDLAND POWER INC

RE: ALBA POWER LIMITED

REQUEST PURPOSE: On Going Work - Current Year

This certifies that the above referenced employer has complied with both the reporting and payment requirements of the Workplace Health, Safety and Compensation Act of Newfoundland and Labrador and is in good standing with the Commission as of today's date.

This certificate expires 45 days from the date of issue. If the above stated purpose has not been satisfied by the expiration date of this certificate, we recommend that you request an additional certificate to protect your business from any potential assessment liability related to this employer.

If you have any questions, please call me at 709 778 1198 or you may use our toll free number noted above if calling within Newfoundland and Labrador.

Sincerely,

Sandra Follett
Enquiry Clerk

L26

# APPENDIX 5
# HYDRO INSPECTION SHEETS
# HARDWOODS AND STEPHENVILLE

# APPENDIX 5
# HYDRO INSPECTION SHEETS
# HARDWOODS AND STEPHENVILLE

HYDRO
THE POWER OF COMMITMENT

**2003-06-10 Rev-01**

# GAS TURBINE
# OPERATOR'S DAILY INSPECTIONS
# UNIT & ASSOCIATED EQUIPMENT

## 1. CONTROL MODULE

a. P C (alarms, printer, paper, etc.)
b. MCC's ( lights, bkr's, on/off, etc.)
c. AVR ( inverter, charger, batteries, etc.)
d. Inergen fire system ( fire panel, pressures, etc.)
e. Check kwhr meters, lights, etc.
f. Building lighting and general safety check.
g. Building heating/air conditioning.

## 2. FUEL FORWARDING MODULE

a. Forwarding pumps ( leaks, pressure, temperature, flow, etc. )
b. Filter/Coalescer ( leaks, pressure across filter, etc. )
c. Inergen fire system ( fire panel, pressures, etc.)
d. Lighting, heating, vents, etc.
e. Sump drains, etc.

## 3. A & B MODULES

GAS GENERATORS

a. Fuel leaks ( lines, fittings, gauges, valves, etc. )
b. Air leaks ( starter, lines, etc. )
c. GG Oil ( levels, leaks, heater, fittings, valves, etc. )
d. Electrical connections.
e. Sump drains

POWER TURBINES

a. Oil leaks ( lines, clutch module, etc. )
b. Blankets and thermocouples ( burnt indication, etc. )
c. Bearing supports ( leaks, wear, etc. )
d. Bellows assembly ( security of attachment, cracks in flanges & volute, etc. )

GENERAL

a. Lighting.
b. Heaters.
c. Coolant leaks.

**4. ALTERNATOR MODULE**

a. Jacking pumps (leaks, gauges, pressure switches, etc. )
b. Exciter area (burn marks, etc.)
c. Bearing supports ( leaks, wear, etc. )
d. Lighting.

**5. AUXILIARY MODULE**

a. Pumps (leaks, pressure, etc. )
b. Demister & evacuator ( leaks, etc. )
c. MLO system (temperature, pressure, leaks, etc. )
d. Glycol system ( temperature, pressure, leaks, etc. )
e. Inergen fire system ( fire panel, pressure, etc.)
f. Lighting.

COMPRESSES AIR SYSTEM
a. Air leaks ( lines safety valves, unloaders, etc. )
b. Compressor oil ( level, color, etc.)
c. Dryer & receiver tanks ( leaks, etc. )

GLYCOL SYSTEM
a. Coolant ( leaks, temperature, etc. )
b. Heat exchangers ( fans, belts, guards, motors, etc )

MISCELLANEOUS
a. Sump level
b. Yard fencing ( signs, holes, etc.)
c. Tank farm ( piping, leaks, vegetation, etc. )
d. Security ( check back gate, fence, etc )

**6. FUEL OFF-LOADING MODULE**

a. Building ( fuel leaks, lighting, heating, vents, etc.)
b. Inergen fire system ( fire panel, pressure, etc. )
c. Varec guage_____m. Oil temperature_____ F.

**7. MAINTENANCE BUILDING**

a. Building ( general condition, lighting, security, etc. )
b. Water supply ( hot/cold water, leaks, etc. )

**8. TERMINAL STATION**

a. Building ( lighting, heating, water, etc. )
b. Recorder – frequency/mw/mvar ( check date, time, paper, etc. )
c. Security ( fire door closed, etc. )
d. Alarms.

**9. REMARKS**

_____
_____
_____
_____

HYDRO
THE POWER OF COMMITMENT

**2003-03-03 Rev 01**

# GAS TURBINE
# UNIT & ASSOCIATED EQUIPMENT
# OPERATOR'S WEEKLY INSPECTIONS

Date: _____ Inspected By: _____

The following areas and associated items must be visually inspected each week:

## *GAS GENERATION*

**Inlet Plenum A:**

____Bird Screens
____Filter Assembly

**Inlet Plenum B:**

____Bird Screens
____Filter Assembly

**Jet Engine A:**

____Leaks (Fuel, Oil, Air)
____Drain Sump
____Heaters
____Clean up Fuel & Oil Drippings

**Jet Engine B:**

____Leaks (Fuel, Oil, Air)
____Drain Sump
____Heaters
____Clean up Fuel & Oil Drippings

**Power Turbine A:**

____Bellows (Cracks)
____Volute Expansion Joint
____Thermocouples
____Bearing Supports
____Blankets

**Power Turbine B:**

____Bellows (Cracks)
____Volute Expansion Joint
____Thermocouples
____Bearing Supports
____Blankets

**Exhaust A:**

____Exhaust Stack (Gen. Cond.)
____Snow Door Pneumatics

**Exhaust B:**

____Exhaust Stack (Gen. Cond.)
____Snow Door Pneumatics

**Clutch A:**

____Oil Leaks
____Grounding Brush
____Clean up Oil Drippings

**Clutch B:**

____Oil Leaks
____Grounding Brush
____Clean up Oil Drippings

## ELECTRICAL GENERATION

**Generator**

____Temperature (Stator & Air)
____Heaters

**Exciter**

____Temperature (Air Out)
____General Condition

## SWITCHGEAR

____General Interior & Exterior Condition
____Station Service Transformer Temp.
(Press F4 on DCS)
____Heaters
____Weatherproof (leaks)

## CONTROL SYSTEMS

____Indicating Lights
____Inverter
____AVR
____Recorders
____Battery Chargers
____Alarms

## FUEL SYSTEM

____Leaks
____Fuel Pressures & Temperatures
____Dip Fuel Tanks as per GAP Regulations.
(Complete Fuel Inventory & Reconciliation Forms and Compare to Tank Gauge & Recorder). F5
____Drains
____Pumps & Valves

**NOTE:** The first working day of each month forward end of month fuel readings to the Production Supervisor.

## COMPRESSED AIR SYSTEM

____Leaks (Oil & Air)
____Air Dryer Condition
____Drain Water Trap
____Indicating Lights

## LUBE OIL SYSTEM

____Pumps (Including Jacking)
____Leaks
____Fans/Evacuator/Demister/Etc.
____Pressure Switches & Gauges

## COOLING SYSTEMS

____Glycol Leaks
____Regulators
____Pumps (Noise)
____Fans (Belts/Guards/ Etc.)
____Temperatures
____General Exterior Condition

## FIRE PROTECTION SYSTEM

____Energen System Pressures
____Accessibility
____Identified
____Panel/Alarms
____CO2 System Pressures
____Accessibility
____Identified

## BUILDING & PROPERTY

____Building Water Supply
____Security System
____Sump Levels
____Heating Systems
____House Keeping
____Tank Farm Dyke
____Pump out Water in Dyke
____General Condition of Building

HYDRO
THE POWER OF COMMITMENT

2003-04-17 Rev 01

# SEMI-ANNUAL INSPECTIONS

# GAS TURBINE

1. Inlet plenum A & B
2. Gas generator A & B
3. Power turbine A & B
4. Exhaust A & B
5. Clutch A & B
6. Fuel forwarding and off-loading
7. Jacking pumps
8. Demister
9. Vent fan
10. Main oil pumps
11. Main oil tank
12. Glycol system
13. Alternator
14. Sump and dykes
15. Fire protection system
16. Air system
17. Battery systems
18. Battery system check sheets (III, V, VI)

**GAS TURBINE**
**UNIT & ASSOCIATED EQUIPEMENT**
**SEMI-ANNUAL INSPECTION**

DATE:_____ INSPECTED BY:_____

Inlet Plenum A:

1. Check condition of bird screens, plenum floor, walls, etc. Remarks: _____

_____

2. Check condition of monoclones, fans & ductwork for cracks & check ladders for security.

Remarks: _____

_____

3. Check condition of inlet filters: Remarks: _____

_____

4. Inspect and check operation of blow-in-doors for freedom of movement and

Operation of alarm limit switches. Remarks: _____

_____

5. Check operation of pressure differential switch for inlet filters, check that tubing is not plugged, etc. Remarks: _____

6. Check inlet compartment for loose objects and foreign materials, and outside doors are sealed with no leaks. Remarks: _____

_____

7. Check the inlet temperature thermocouple reading on computer with a digital thermometer held next to thermocouple probe. Remarks: _____

_____

8. Check louvers for freedom of movement, etc, on enclosure fans 1 & 2 GGA.

Remarks: _____

**Inlet Plenum B.**

1. Check condition of bird screens, plenum floor, walls, etc. Remarks: _____

_____

2. Check condition of monoclones, fans & ductwork for cracks & check ladders for security.

Remarks: _____

_____

3. Check condition of inlet filters: Remarks: _____

_____

4. Inspect and check operation of blow-in-doors for freedom of movement and operation of alarm limit switches in control room. Remarks: _____

_____

5. Check operation of pressure differential switch for inlet filters, check that tubing is not plugged, etc. Remarks: _____

6. Check inlet compartment for loose objects and foreign materials, and outside doors are sealed with no leaks. Remarks: _____

_____

7. Check the inlet temperature thermocouple reading on computer with a digital thermometer held next to thermocouple probe. Remarks: _____

_____

8. Check louvers for freedom of movement, etc. on enclosure fans 1 & 2 GGB Remarks: _____

**Gas Generator A:**

1. Inspect the five chip detectors for metallic deposits (refer to C.W. Manual, volume 111 7.2.1.2-14) Remarks: _____

_____

2. Check for cracks in nose bullet. Remarks: _____

3. Clean entry guide vanes and inspect with extension light and mirror. If indication of cracks, investigate using dye penetrate procedure. Also inspect the first stage compressor shrouded stators (refer to C.W. Manual, Volume 111 7.2.1.2/1-3) Remarks: _____

_____

4. Drain and refill the air starter with 150cc.( 5oz.) of clean generator lubricating oil. Remarks: _____

5. Inspect the ignition units and igniter plugs. Check for security of connections and any physical damage. Remarks: _____

_____

6. Check all fuel, oil and airlines for condition and security of connections. Remarks:_____

7. Inspect and lubricate the fuel pressure regulator (LF-4) shaft and check for leaks. Remarks: _____

8. Inspect liquid fuel valve and actuator for loose bolts, oil leaks, wear, binding and security of mounting. Remarks: _____

9. Remove the air system strainer screen (ST-CA-1 ) Inspect and clean, check the air regulating system components for leaks, cleanliness, etc. Remarks: _____

_____

10. Inspect and lubricate the fuel fire valve plunger rod to assure freedom of operation.

Remarks: _____

11. Check the security of the supplementary fuel pump/motor assembly. Check the supplementary fuel filter indicator. Clean/change filter if required. Remarks: _____

_____

12. Check all junction boxes for security of terminals, tidiness, overheating, etc. Remarks: _____

13. Inspect combustion chamber outer casing general condition. Inspect the engine to power turbine bellows for dents, distortion, hot spots, etc.
Remarks:_____

14. Check lube oil tank level using the dipstick level indicator. Top up as required.
Remarks:_____

15. Check that the drainage hole is clear and free. Remarks:_____

16. Check forced air heaters, lubricate motors if required.
Remarks:_____

**Gas Generator B**

1. Inspect the five chip detectors for metallic deposits (refer to C.W. Manual, Volume 111 7.2.1.2-14) Remarks: _____

_____

2. Check for cracks in nose bullet. Remarks : _____

3. Clean entry guide vanes and inspect with extension light and mirror. If indication of cracks, investigate using dye penetrate procedure. Also inspect the first stage compressor shrouded stators (refer to C.W. Manual, Volume 111 7.2.1.2/1-3) Remarks: _____

_____

4. Drain and refill the starter with 150 cc.(5 oz.) clean generator lubricating oil.

Remarks: _____

5. Inspect the ignition units and igniter plugs. Check for security of connections and any physical damage. Remarks: _____

6. Check all fuel, oil, and airlines for condition and security of connections.

Remarks: _____

7. Inspect and lubricate the fuel pressure regulator (LF-4) shaft and check for leaks.

Remarks: _____

8. Inspect liquid fuel valve and actuator for loose bolts, oil leaks, wear binding and security of mounting. Remarks: _____

9. Remove air system strainer screen (ST-CA-1) Inspect and clean, check the air regulating system components for leaks, cleanliness, etc. Remarks: _____

_____

10. Inspect and lubricate the fire fuel valve plunger rod to assure freedom of operation.

Remarks: _____

11. Check the security of the supplementary fuel pump/motor assembly. Check the supplementary fuel filter indicator. Clean/change filter if required. Remarks: _____

_____

12. Check all junction boxes for security of terminals, tidiness, overheating, etc.

Remarks: _____

13. Inspect combustion chamber outer casing general condition. Inspect the engine to power turbine bellows for dents, distortion, hot spots, etc.
Remarks:_____

14. Check lube oil tank level using the dipstick level indicator. Top up as required.
Remarks:_____

15. Check that the drainage hole is clear and free. Remarks:_____

16. Check forced air heaters in modules, lubricate motors if required.
Remarks:_____

**Power Turbine A:**

1. Check the security of thermocouple terminations, etc.

Remarks: _____

2. Inspect the power turbine cover blankets for general condition.

Remarks: _____

3. Check vibration detectors security of pickup and connections.

Remarks: _____

4. Inspect the front and rear bearing supports for oil seepage at covers. Check all hold down bolts, etc. Remarks: _____

5. Inspect the exhaust volute general condition, mount supports and load reference indication (refer to C.W. Operation & Maintenance Manual, Section 2.2.2.2) Remarks:

_____

6. Inspect the inside of the power turbine volute for falling objects, cracks, loose or defective deflector rings, etc.

a) 1 Inspect bolts for evidence of any bolt movement, broken wire or broken tac weld.
b) Remove and discard any bolts showing signs of being dislodged.
c) Clean threaded bolt holes.
d) Clean existing tac weld material.
e) Install new bolts to recommended torque of 90 +/- 5 in-lb (see attached service bulletin), (use washers only if they were supplied with the bolts when they were purchased).
f) Reinstall all lock wires.
g) Put a small tac weld between the head of each bolt and the ring.
h) Put the tac weld between the deflector ring and the casing.

Remarks:_____

**Power Turbine B**:

1. Check the security of thermocouple terminations, etc. Remarks: _____

_____

2. Inspect the power turbine cover blankets for general condition. Remarks: _____

_____

3. Check the vibration detectors security of pickup and connections. Remarks: ___

_____

4. Inspect front & rear bearing supports for oil seepage at covers. Check all hold down bolts, etc. Remarks: _____

5. Inspect exhaust volute general condition, mount supports & load reference indication (refer to C.W. Operation & Maintenance Manual, section 2.2.2.2) Remarks:

_____

5. Inspect the inside of the power turbine volute for falling objects, cracks, loose or defective deflector rings, etc. Remarks: _____

**Exhaust A:**

1. Check the exhaust stack inside wall panels for security of insulation, plates, etc. Remarks; _____

2. Check snow doors and cylinders for ease of operation, lubricate as required. Check operation of limit switches, wiring, air leaks, etc. Remarks:

_____

**Exhaust B:**

1. Check the exhaust stack inside wall panels for security of insulation, plates etc.

Remarks: _____

2. Check snow doors and cylinders for ease of operation, lubricate as required. Check operation of limit switches, wiring, air leaks, etc. Remarks:

_____

**Clutch A:**

1. Check the clutch box base hold down bolts. Inspect grounding brush. Remarks:

_____

**Clutch B:**

1. Check the clutch box base hold down bolts. Inspect grounding brush. Remarks:

_____

**Fuel forwarding & off-loading:**

1. Check the filter vessels, heater vessel, etc. for fuel leaks. Note: Fuel temperature:_____ and Pressure:_____.
   Remarks_____

2. Check fuel forwarding and off-loading pumps for leaks, etc. grease as required.
   Remarks:_____

3. Check fuel flow meters for leaks, etc.
Remarks:_____

4. Lubricate all manual valves as required.
Remarks:_____

5. Check diesel generator tank for leaks, level etc.
Remarks_____

6. Check turbine oil storage for leaks, etc.
Remarks:_____

7. Check that the drainage hole is free and clear.
Remarks:_____

**Jacking Pumps:**

1. Check motor brushes. Remarks: _____

2. Check operation pressures & shaft lift (both ends) with a dial indicator.
Note:

The following motors must be on prior to performing this test Evacuator, Demister,

MLO pump & Jacking Pump. Remarks:_____

_____

3. Check pump and fittings for leaks. Check hold down bolts & grease motor

bearings if required. Remarks:
_____

**Demister:**

1. Inspect mounting hardware, hose and connections. Check for oil leaks, vibration etc. Remarks: _____

_____

2. Clean/change filter as required. Remarks: _____

**Vent Fan:**

1. Check mounting bolts, fan, fan coupling, louver free to move, etc. Remarks:

_____

**Main Oil Pumps:**

1. Check for oil leaks, pressure and general condition. Grease bearings as required.

Remarks: _____

2. Check brushes DC motors. Remarks: _____

**Main oil Tank:**

1. Drain condensation from main tank. Use valve at bottom of tank. Remarks: ___

_____

2. Check level of oil in tank,(dipstick) add as required. Remarks: _____

_____

**Glycol system:**

1. Check cooling fans pitch angle settings & general condition of blades. Remarks:

_____

2. Check tightness & condition of belts. Remarks: _____

3. Lubricate all manual valves, flow control valves, etc. and grease bearings as required.

Remarks: _____

4. Check for leaks, and check expansion tank glycol level. Make note of tank level. Check low level alarm switch. Remarks:

_____

5. Drain off some glycol and check contamination content and protection level. Remarks:_____

6. Check heat exchanger cooling tubes and vanes for leaks, rust, etc. Remarks:

_____

7. Check the condition and operation of the three-way thermostat. (lubricate all moving parts)

Remarks: _____

**Alternator:**

1. Check condition of filters. Remarks: _____

2. Check filter block switch, (check hose is not let go or pinched) Remarks: _____

_____

3. Check alternator louvers, make sure they are free to move. Remarks: _____

_____

4. Check alternator anti-condensation heaters, load readings, etc. Remarks:

_____

5. Check doors and ladders for security.
Remarks:_____

6. Check earth fault indication brush. Remarks_____

**Sump & Dykes:**

1. Check level of fluid in sump. Operate level switch to get alarm in control room.

Arrange to have sump pumped out if close to level switch. Remarks:_____

_____

2. Check drain valve main tank for water & dirt contamination. Remarks _____

_____

3. Check and grease all fuel valve stems, & associated equipment. Remarks: _____

_____

4. Check steps to tank and hand rails (over dyke) for security etc. Remarks: _____

_____

5. Check steps & handrail on tank for security etc. Remarks: _____

_____

6. Check tank sides, roof, & associated piping for excessive rust, etc. Remarks:

_____

7. Check for debris & weeds inside dyke. Remarks: _____

_____

8. Check to make sure no liner in dyke is exposed. Remarks: _____

_____

9. Check varec gauge for freedom of movement, reading compares with fuel dips.

Remarks: _____

10. Check lighting tank farm.(operate photo cell for lighting.) Remarks: _____

_____

11. Check fuel lines, expansion joints, etc., for leaks, rust, etc. Remarks _____

_____

**FIRE PROTECTION SYSTEM**
**SEMI-ANNUAL INSPECTIONS**

The following checks should be preformed during an Inergen system inspection:

1. Visually inspect area to verify it has not changed, look for blocked open doors or dampers, new equipment, etc.
2. Check detectors to make certain they are in place, not damaged or coated with dirt grease, paint or any contamination.
3. Check all manual pull stations, make sure they are not blocked from use.
4. Check all alarm devices for damage, dirt or corrosion.
5. Check piping is secure and nozzles are in place and not covered with dirt, etc.
6. Verify all pressure switches are in place and in the non-operated position.
7. Visually verify control panel is functioning properly. Power light on, no alarms.
8. Check each cylinder indicator gauge to determine that the cylinder pressure is in the operable range. (Green) Record pressure.

Inergen Fire Systems:
---

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| End A Module | Cylinder Pressure | ____ | ____ | ____ | ____ | ____ | ____ |
| Aux. Module | Cylinder Pressure | ____ | ____ | ____ | ____ | ____ | ____ |
| End B Module | Cylinder Pressure | ____ | ____ | ____ | ____ | ____ | ____ |
| Exciter Module | Cylinder Pressure | | ____ | ____ | | | |
| Control Module | Cylinder Pressure | | ____ | ____ | | | |
| Fuel Forward Module | Cylinder Pressure | | ____ | ____ | ____ | ____ | |
| Fuel Off-loading Module | Cylinder Pressure | | ____ | ____ | ____ | ____ | |

Remarks:_____
_____

NOTES:_____

**COMPRESSOR/DRYER/ AIR SYSTEM**
**Semi-annual inspection**
**Station**_____ **Date**_____ **Name**_____

DEW POINT TEMP: _____ $^0$C AMBIENT TEMPERATURE: _____ $^0$C

| | COMP. #1 | COMP. #2 | DRYER |
|---|---|---|---|
| Counter | | | |
| Replace Pre-Filter | | | |
| Replace After-Filter | | | |
| Clean Unloader Valve | | | |
| Change Desiccant (if required) | | | |
| Changed Base Oil | | | |
| Moisture Discharge | | | |
| High Temperature Alarm | | | |
| Oil Level Alarm | | | |
| Motor Amps | | | |
| Check Safety Relief Valves | | | |

FUNCTION TEST SYSTEM:

Lead Comp. #1: Cut In _____ Cut Out _____ Running Time _____
Lead Comp. #2: Cut In _____ Cut Out _____ Running Time _____
Lag Comp. Pressure Switch Cut In _____ Cut Out _____
High Side: High Pressure Alarm: _____ Low Pressure Alarm: _____
Low Side: High Pressure Alarm: _____ Low Pressure Alarm: _____
Differential Pressure: _____ 15 min Pressure Drop: _____

CHECKS COMPLETED:

_____ Check/clean outlet and purge check valve assemblies
_____ Check/clean inlet & purge exhaust switching valves
_____ Check oil relief valves, check valves, and pressure gauges
_____ Check belt drives for tension and wear
_____ Check dryer failure alarm
_____ Check for oil & air leaks in the system
_____ Check guards/couplers
____ Check/clean the re-pressurization valve
____ Check limit switches, and flow switches operation
____ Operate storage tank relief valves
____ Check all motor contactors,wiring,and bearing
____ Check thermostats & all electrical controls
___ Check pressure drop across prefilter & afterfilter
___ Check flex connections

CAUTION: Before inspection and maintenance of the compressor, be sure to shut off starting switch .

Note Any Concerns Below:

_____

_____

**BATTERY BANK SEMI-ANNUAL INSPECTIONS**
(Liberty 2000 Sulfuric Acid, sealed.)

DATE:_____ INSPECTED BY:_____

Bus Voltage:_____V.DC Bus Amperage:_____Amps.

Pilot Cell No._____ Voltage Pilot Cell._____V. DC

Position Found Float:_____ Equalize_____

Position left, Float:_____ Equalize_____

_____Check each cell for cracks, corrosion on terminals, leaks and swelling.
_____Clean, lubricate and tighten battery connections if needed.
_____Check the operation of ventilation fans and thermostat.
_____Check the operation of emergency lighting.

Only if Required:

_____Complete capacity ( discharge ) test of battery bank.
_____Conduct resistance test of cell-cell connections.( form VI)
_____Collect cell internal ohmic values. (form III)
_____Conduct individual cell temperature and voltage test. (form V)

Remarks:_____

DIESEL GENERATOR CHARGER & BATTERIES

Bus Voltage: _____ V. DC Bus Amperage: _____ Amps.

Position Found Float: _____ Equalize : _____

Position Left, Float: _____ Equalize: _____

_____Check each battery for cracks, corrosion on terminals, leaks and swelling.
_____Clean, lubricate and tighten battery connections if needed.

Remarks: _____

Turn on fuel at day tank, fuel forwarding module, to start Diesel, run for a few minutes, shut down Diesel, turn off fuel at day tank.
Remarks: _____
Form III- VRLA Battery Cell Inspection

Manufacturer_____ Serial #_____
Readings By_____ Date_____

| Cell No. | Impedance | Conductance | Resistance | Cell No. | Impedance | Conductance | Resistance |
|---|---|---|---|---|---|---|---|
| 1 | | | | 31 | | | |
| 2 | | | | 32 | | | |
| 3 | | | | 33 | | | |
| 4 | | | | 34 | | | |
| 5 | | | | 35 | | | |
| 6 | | | | 36 | | | |
| 7 | | | | 37 | | | |
| 8 | | | | 38 | | | |
| 9 | | | | 39 | | | |
| 10 | | | | 40 | | | |
| 11 | | | | 41 | | | |
| 12 | | | | 42 | | | |
| 13 | | | | 43 | | | |
| 14 | | | | 44 | | | |
| 15 | | | | 45 | | | |
| 16 | | | | 46 | | | |
| 17 | | | | 47 | | | |
| 18 | | | | 48 | | | |
| 19 | | | | 49 | | | |
| 20 | | | | 50 | | | |
| 21 | | | | 51 | | | |
| 22 | | | | 52 | | | |
| 23 | | | | 53 | | | |
| 24 | | | | 54 | | | |
| 25 | | | | 55 | | | |
| 26 | | | | 56 | | | |
| 27 | | | | 57 | | | |
| 28 | | | | 58 | | | |
| 29 | | | | 59 | | | |
| 30 | | | | 60 | | | |

Form V- Battery Cell Inspection

Manufacturer_____ Serial #_____
Readings By_____ Date_____

| Cell No. | Voltage | Temp (°C) | Cell No. | Voltage | Temp (°C) | Cell No. | Voltage | Temp (°C) |
|---|---|---|---|---|---|---|---|---|
| 1 | | | 21 | | | 41 | | |
| 2 | | | 22 | | | 42 | | |
| 3 | | | 23 | | | 43 | | |
| 4 | | | 24 | | | 44 | | |
| 5 | | | 25 | | | 45 | | |
| 6 | | | 26 | | | 46 | | |
| 7 | | | 27 | | | 47 | | |
| 8 | | | 28 | | | 48 | | |
| 9 | | | 29 | | | 49 | | |
| 10 | | | 30 | | | 50 | | |
| 11 | | | 31 | | | 51 | | |
| 12 | | | 32 | | | 52 | | |
| 13 | | | 33 | | | 53 | | |
| 14 | | | 34 | | | 54 | | |
| 15 | | | 35 | | | 55 | | |
| 16 | | | 36 | | | 56 | | |
| 17 | | | 37 | | | 57 | | |
| 18 | | | 38 | | | 58 | | |
| 19 | | | 39 | | | 59 | | |
| 20 | | | 40 | | | 60 | | |

**Table 1: Take temperature readings at the negative terminal of cells.**

Form VI- Battery Cell Inspection

Manufacturer_____ Serial #_____
Readings By_____ Date_____

**Clean & re-torque any connections with high resistance readings**

| Meter Probes Between Cell Posts | As-Found (Micro-Ohms) | As-Left (Micro-ohms) | Meter Probes Between Cell Posts | As-Found (Micro-Ohms) | As-Left (Micro-Ohms) |
|---|---|---|---|---|---|
| Lug & No. 1 | | | 30 – 31 | | |
| 1 – 2 | | | 31 – 32 | | |
| 2 – 3 | | | 32 – 33 | | |
| 3 – 4 | | | 33 – 34 | | |
| 4 – 5 | | | 34 – 35 | | |
| 5 – 6 | | | 35 – 36 | | |
| 6 – 7 | | | 36 – 37 | | |
| 7 – 8 | | | 37 – 38 | | |
| 8 – 9 | | | 38 – 39 | | |
| 9 – 10 | | | 39 – 40 | | |
| 10 – 11 | | | 40 – 41 | | |
| 11 – 12 | | | 41 – 42 | | |
| 12 – 13 | | | 42 – 43 | | |
| 13 – 14 | | | 43 – 44 | | |
| 14 – 15 | | | 44 – 45 | | |
| 15 – 16 | | | 45 – 46 | | |
| 16 – 17 | | | 46 – 47 | | |
| 17 – 18 | | | 47 – 48 | | |
| 18 – 19 | | | 48 – 49 | | |
| 19 – 20 | | | 49 – 50 | | |
| 20 – 21 | | | 50 – 51 | | |
| 21 – 22 | | | 51 – 52 | | |
| 22 – 23 | | | 52 – 53 | | |
| 23 – 24 | | | 53 – 54 | | |
| 24 – 25 | | | 54 – 55 | | |
| 25 – 26 | | | 55 – 56 | | |
| 26 – 27 | | | 56 – 57 | | |
| 27 – 28 | | | 57 – 58 | | |
| 28 – 29 | | | 58 – 59 | | |
| 29 – 30 | | | 59 - 60 | | |
| | | | No. 60 & lug | | |

HYDRO
THE POWER OF COMMITMENT

2005-02-15 Rev 02

# GAS TURBINES
# ANNUAL INSPECTUONS

1. Take oil samples from GGA, GGB, MLO.

2. Complete a tool inventory.

3. Complete a spill control inventory.

4. Check Sump Level Indicators/Switch.

5. Check Operation of Fuel Level Switches.
( SVLGT Only )

HYDRO
THE POWER OF COMMITMENT

2005-03-30 Rev 02

# GAS TURBINE

## 5 Year Inspections

These inspections will be completed on a 5 year interval :

1. Change all lube oil filters.
2. Change all fuel filters.
3. Change all air filters.
4. Check IRD Vibraction Equipment

Check all relevant equipment after changing filters.

HYDRO
THE POWER OF COMMITMENT

2003-06-10 Rev 01

# Gas Turbine

# P&C 6 year inspections

These items are to be inspected on a 6 year interval :

1. Relay trip 86 and 94.
2. Relay protection timers, elect/mech.
3. Relay protection timers, electronic.
4. Electronic protection relays.
5. Relays, elect/mech., C/V solenoid type.
6. Relays, elect/mech., C/V induction type.
7. Transducers.
8. Panel metering.
9. Metal-clad Switchgear.
10. Transformers.

HYDRO
THE POWER OF COMMITMENT

2003-06-10

# METAL CLAD SWITCHGEAR

BEFORE OPERATING: Counter: _____

DUCTOR TEST 100 A (micro ohms)
A Phase: _____ B Phase: _____ C Phase: _____

| Complete these tests only if instructed | | | |
|---|---|---|---|
| Timing Test | A | B | C |
| Close | | | |
| Trip | | | |
| Doble Test | | | |
| Inspect Arcing Chamber | | | |

| Command Current | |
|---|---|
| Close_____ Amps | Trip_____ Amps |

CONTROL COIL RESISTANCE (ohms):
Trip: _____ Close: _____

MEGGER TEST 5 kV (breaker in open position):

A _____ Mega ohms B _____ Mega ohms C _____ Mega ohms

AFTER OPERATING: Counter: _____

CHECKS COMPLETED:

_____ Lubricate Control Block
_____ Check Primary Connections
_____ Check and lubricate latching pawl mechanism
_____ Check erosion indicator, wipes and gaps
_____ Perform vacuum interrupter integrity test

# Gas Turbine Test Run (HWD & SVL)

Station: Date:

Local Operator:

ECC Operator:

| Test Condition | Time | Load (MW) If Applicable | Successful | | Alarms | | Trend Data Filed | |
|---|---|---|---|---|---|---|---|---|
| | | | Yes | No | Yes | No | Yes | No |
| With unit shut down start GGA in Generate Mode and run to full load | | | | | | | | |
| Maintain full load for 10 minutes | | | | | | | | |
| Shut down GGA | | | | | | | | |
| With unit shut down start GGB in Generate Mode and run to full load | | | | | | | | |
| Maintain full load for 10 minutes | | | | | | | | |
| Shut down GGB | | | | | | | | |
| With unit shut down start GGA & GGB in Generate Mode and load to 10 MW (5 MW each end) | | | | | | | | |
| Change MW and MVAR set points to verify functionality (Local & ECC) | | | | | | | | |
| Switch to Sync Condense Mode and shut down GGA & GGB | | | | | | | | |
| With unit in Sync Condense select GGA start and go to generate at 5 MW | | | | | | | | |
| Select Sync Condense and shut down GGA | | | | | | | | |
| With unit in Sync Condense select GGB start and go to generate at 5 MW | | | | | | | | |
| Select Sync Condense and shut down GGB | | | | | | | | |
| With unit in Sync Condense select GGA & GGB start and go to generate at 10 MW (5 MW each end) | | | | | | | | |

Print and file trend data for all tests.

Record all alarms and anomalies in the attached notes section.

Notes:

# APPENDIX 6
# REFURBISHMENT RECOMMENDATIONS COST ESTIMATE SPREADSHEET HARDWOODS AND STEPHENVILLE

# COST ESTIMATE SPREADSHEET No. 1
# HARDWOODS GAS TURBINE FACILITY
# REFURBISHMENT RECOMMENDATIONS

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Newfoundland and Labrador Hydro** | | | | | | | | | | | | |
| **Stephenville and Hardwoods Gas Turbine Condition Assessment Study** | | | | | | | | | | | | |
| **NG Job No. 21061** | | | | | | | | | | | | |
| **Rev 1 ------ 2007-12-14** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | **COST ESTIMATE SPREADSHEET No. 1** | | | | | | | | | | |
| | **HARDWOODS GAS TURBINE REFURBISHMENT RECOMMENDATIONS** | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **Item** | | **Hardwoods Recommendations** | | | | | | | | **Cost Total** | | |
| | | | | | | | | | | | | |
| **1--** | | **Gas Generators / Power Turbines Equipment** | | | | | | | | | | |
| | | | | | | | | | | | | |
| 1 | | Engine A assembly be removed, disassembled to allow for | | | | | | | | | | |
| | | detailed internal inspection with major refurbishments as required | | | | | | | | | | |
| | | (Report para. 5.2.1) | | | | | | | | | | |
| | | o S&S Turbines Cost to refurbish and test engine assembly in BC | | | | | | | | $515,000.00 | | |
| | | o Cost to transport engine assembly to BC & back | | | | | | | | 3,200.00 | | |
| | | o Engine removal & reinstallation by S&S Turbines Technicians | | | | | | | | 14,000.00 | | |
| | | | | | | | | | | | | |
| 2 | | Engine B assembly be removed, disassembled to allow for | | | | | | | | | | |
| | | detailed internal inspection with major refurbishments as required | | | | | | | | | | |
| | | (Report para. 5.2.1) | | | | | | | | | | |
| | | o S&S Turbines Cost to refurbish and test engine assembly in BC | | | | | | | | $460,000.00 | | |
| | | o Cost to transport engine assembly to BC & back | | | | | | | | 3,200.00 | | |
| | | o Engine removal & reinstallation by S&S Turbines Technicians | | | | | | | | 14,000.00 | | |
| | | | | | | | | | | | | |
| 3 | | Inspect the Power Turbine assemblies A & B in detail upon removal of | | | | | | | | $120,000.00 | | |
| | | the Engines as noted in Items 1 & 2 to verify the mechanical integrity | | | | | | | | | | |
| | | of the units. Inspect and refurbish the following: (Report para. 5.2.5) | | | | | | | | | | |
| | | o Main line bearings inspection | | | | | | | | | | |
| | | o Remove turbine blades and perform metallurgical sampling to | | | | | | | | | | |
| | | verify alloy composition and wear to the blade roots | | | | | | | | | | |
| | | o Remove turbine disks and perform metallurgical sampling to verify | | | | | | | | | | |
| | | alloy composition and creep growth. | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | o Apply anti-corrosion/thermal protection coatings to the turbine | | | | | | | | | | | | | |
| | | blades and nozzles. | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 4 | | Completely disassemble and inspect the Power Turbine Clutches A & B. | | | | | | | | | | | $13,000.00 | | |
| | | Determine and resolve the interference problem between the clutches | | | | | | | | | | | | | |
| | | and the proximity switches. (Report para. 5.2.6) | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 5 | | Spare Item | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 6 | | Spare Item | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 7 | | It is recommended that HYDRO replace the following obsolete | | | | | | | | | | | | | |
| | | auxiliary components with components of current design: | | | | | | | | | | | | | |
| | | (Report para. 5.2.2) | | | | | | | | | | | | | |
| | | **Quantity** | | **Device** | | | | | | | | | | | |
| | | | o | Replace Ignition Exciters | | | | | | | | | $24,000.00 | | |
| | | | o | Replace Speed Governors/fuel valve assemblies | | | | | | | | | $56,000.00 | | |
| | | | | | | | | | | | | | | | |
| 8 | | **Option:** | | | | | | | | | | | | | |
| | | S&S Turbines provides a rental engine for the period when an engine | | | | | | | | | | | | | |
| | | leaves site for refurbishment in BC until its return to site (estimated at | | | | | | | | | | | | | |
| | | 120 days per engine - assumes only one engine off-site at any time) | | | | | | | | | | | | | |
| | | o 120 days per engine x 2 = 240 days (8 months) | | | | | | | | | | | | | |
| | | o Fee for installation and removal = $14,000.00 | | | | | | | | | | | | | |
| | | o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00 | | | | | | | | | | | | | |
| | | o Fired hour charge = $42.00 per hour | | | | | | | | | | | | | |
| | | (Assume 60 hours in 8 months = $2,520.00) | | | | | | | | | | | | | |
| | | o Return transport from/to BC = $5,200.00 | | | | | | | | | | | | | |
| | | | | **Total:** | | | | | | | | | $41,320.00 | | $1,263,720.00 |
| | | | | | | | | | | | | | | | |
| **2--** | | **Inlet Air Systems A & B** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 9 | | Interior of both Inlet Air Plenums A and B be sand blasted and the | | | | | | | | | | | $ 18,000 | | |
| | | surface of the Inlet Air Plenums and the silencers re-coated. | | | | | | | | | | | | | |
| | | (Report para. 5.2.3) | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 10 | | The exterior of both Inlet Air Structures be cleaned of surface corrosion | | | | | | | | | | | $ 24,000 | | |

| | | |

| | | | | |
|---|---|---|---|---|
| 20 | Repair cracks at two corners of the Exhaust Stack B access door opening in the inner liner, as well as cracks in the inner liner below the door opening and the internal rolled edge. (Report para. 5.2.4) | $ 1,200 | | |
| 21 | Replace the snow doors on each Exhaust Stack. (Report para. 5.2.4) | $ 34,000 | | |
| 22 | Replace existing access doors on the Exhaust Stacks with operable hinged doors with proper flashings and weather stripping In addition, modify the hatches below these doors, in the roof of the gas turbine enclosures, to prevent water leaks. (Report para. 5.2.4) | $ 16,500 | | |
| 23 | Replace the ladders providing access to the platforms on each Exhaust Stack. (Report para. 5.2.4) | $ 5,500 | | $ 95,000 |
| **4--** | **Glycol Cooler for Main Lube Oil** | | | |
| 24 | The entire Glycol Cooler steel structure and associated cladding be cleaned, prepared and re-coated within next 2 years. (Report para. 5.2.9) | $ 9,500 | | $ 9,500 |
| **5--** | **Gas Generator / Power Turbine Enclosures A & B** | | | |
| 25 | The exterior of both Gas Generator / Power Turbine Enclosures be cleaned of corrosion, prepared and re-coated within next 2 years. (Report para. 5.2.10) | $ 10,000 | | |
| 26 | The interior of both Gas Generator / Power Turbine Enclosures be cleaned, areas with corrosion sandblasted and re-coated. (Report para. 5.2.10) | $ 11,000 | | |
| 27 | Modify the existing man doors to both Power Turbine Modules to have inspection windows added. (Report para. 5.2.10) | $ 1,600 | | $ 22,600 |
| **6--** | **Alternator & Excitation System** | | | |
| 28 | Conduct Electrical Tests on the Alternator and Exciter while in its | $7,000.00 | | |

| | | | | |
|---|---|---|---|---|
| | | enclosure to determine condition as follows: (Report para. 5.3.3) | | |
| | | o Alternator Stator EL-CID Test | | |
| | | o Alternator Stator Polarization Index Test | | |
| | | o Alternator Stator Partial Discharge Test | | |
| | | o Alternator Rotor Megger Test - 500 vdc | | |
| | | o Measure Alternator Rotor Winding Resistance | | |
| | | o Rotating Exciter Stator and Rotor Megger Tests | | |
| | | o Measure Rotating Exciter Stator and Rotor Winding Resistance | | |
| | | | | |
| 29 | | Remove & replace the Alternator from its Enclosure and remove the rotor | $50,000.00 | |
| | | for a complete visual inspection of the stator / rotor / exciter. Inspections | | |
| | | shall include: (Report para. 5.3.3) | | |
| | | | | |
| | | Stator Inspection to include but not limited to: | | |
| | | o Loose or damaged Wedges | | |
| | | o Loose or cracked or failed winding connections | | |
| | | o Dusting, greasing and other signs of windings movement | | |
| | | o Indications of arcing (hot spots) and damaged core laminations | | |
| | | o Loose core bolts | | |
| | | o Signs of corrosion, contamination and excessive dirt | | |
| | | | | |
| | | Rotor Inspection to include but not limited to: | | |
| | | o Signs of physical damage | | |
| | | o Loose or cracked or failed winding connectors | | |
| | | o Slot wedge migration and possible contact with retaining rings | | |
| | | o Signs of overheating | | |
| | | o Loose rotor wedges | | |
| | | o Dye penetrant examinations and magnetic particle tests on | | |
| | | forgings; retaining rings and fan components to detect | | |
| | | fatigue cracks. | | |
| | | | | |
| | | Bearings Inspection to include but not limited to: | | |
| | | o Assess general condition of the bearings | | |
| | | o Determine if the bearings require re-babbiting or machining. | | |
| | | | | |
| | | Carry out refurbishment work as required following | | |
| | | completion of electrical tests (Item 27) and visual inspections | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (Item 28). Estimate includes: | | | | | | | | | | |
| | | o Rewind of stator at supplier's shop | | | | | | | | $1,200,000.00 | | |
| | | o Rewind of rotor c/w new end caps and overspeed testing at | | | | | | | | $800,000.00 | | |
| | | supplier's shop | | | | | | | | | | |
| | | o Rewind /refurbishment of exciter | | | | | | | | $25,000.00 | | |
| | | o Transport costs to/from supplier's shop - assume UK | | | | | | | | $30,000.00 | | |
| | | | | | | | | | | | | |
| 30 | | Perform a trim balance on the rotor to address the vibration issue | | | | | | | | $10,000.00 | | |
| | | observed physically and noted on the vibration monitoring system. | | | | | | | | | | |
| | | There is a residual imbalance between the non-exciter and exciter | | | | | | | | | | |
| | | of the alternator. (Report para. 5.2.7) | | | | | | | | | | $2,122,000.00 |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **7--** | | **Alternator Enclosure** | | | | | | | | | | |
| | | | | | | | | | | | | |
| 31 | | The exterior of the Alternator Enclosure be cleaned to remove surface | | | | | | | | $ 9,000 | | |
| | | corrosion and flaking, prepared and re-coated within next 2 years. | | | | | | | | | | |
| | | (Report para. 5.3.7) | | | | | | | | | | |
| | | | | | | | | | | | | |
| 32 | | Add inspection windows to the man doors in the alternator module | | | | | | | | $ 1,600 | | |
| | | for safety purposes. (Report para. 5.3.7) | | | | | | | | | | $ 10,600 |
| | | | | | | | | | | | | |
| **8--** | | **Fuel oil System** | | | | | | | | | | |
| | | | | | | | | | | | | |
| 33 | | Clean, prepare and re-coat the storage tank exterior within the next | | | | | | | | $ 40,000 | | |
| | | 5 to 7 years. (Report para. 5.4.1) | | | | | | | | | | |
| | | | | | | | | | | | | |
| 34 | | Clean, prepare and re-coat the storage yank stairs and handrail within | | | | | | | | $ 4,000 | | |
| | | the next 2 to 3 years. (Report para. 5.4.1) | | | | | | | | | | |
| | | | | | | | | | | | | |
| 35 | | Replace two corrode stair treads on the storage tank stairs. (Report | | | | | | | | $ 750 | | |
| | | para. 5.4.1) | | | | | | | | | | |
| | | | | | | | | | | | | |
| 36 | | Install a kickplate at the handrail on the top of the storage tank. | | | | | | | | $ 500 | | |
| | | (Report para. 5.4.1) | | | | | | | | | | $ 45,250 |
| | | | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **9--** | | **Electrical Systems** | | | | | | | | | |
| | | | | | | | | | | | |
| 37 | | Replace the alternator existing 13.8 kV circuit breaker with a new | | | | | | | $60,000 | | |
| | | circuit breaker. (Report para. 5.5.1) | | | | | | | | | |
| | | | | | | | | | | | |
| 38 | | Modify cabling in the 13.8 kV cable entrance cubicle as follows: | | | | | | | | | |
| | | o Short term - install dividers to separate the power cables from the | | | | | | | $3,500.00 | | |
| | | control and instrumentation cables. | | | | | | | | | |
| | | o Long term - Replace and install power cables in a separate | | | | | | | $9,500 | | |
| | | compartment from the control and instrumentation cables. | | | | | | | | | |
| | | (Report para. 5.5.1) | | | | | | | | | |
| | | | | | | | | | | | |
| 39 | | Repair bus duct leaks by either (i) applying rubberized asphalt roofing | | | | | | | $6,000 | | |
| | | compound over the duct or (ii) cover the bus duct with cladding. | | | | | | | | | |
| | | (Report para. 5.5.3) | | | | | | | | | |
| | | | | | | | | | | | |
| 40 | | Replace the existing 125 Vdc Battery Charger due to obsolence. | | | | | | | $17,000 | | |
| | | (Report para. 5.5.5) | | | | | | | | | |
| | | | | | | | | | | | |
| 41 | | Recommendation for HYDRO to prepare a replacement program and | | | | | | | $21,000 | | |
| | | budget to replace over time the electro-mechanical generator | | | | | | | | | |
| | | protection relays with digital relays. (Report para. 5.5.6) | | | | | | | | | |
| | | | | | | | | | | | |
| 42 | | Replace the 15 kV power cable supplying the 750 kVA Station Service | | | | | | | $6,100 | | |
| | | Transformer. (Report para. 5.5.7) | | | | | | | | | $123,100 |
| | | | | | | | | | | | |
| **10--** | | **Control & Instrumentation Systems** | | | | | | | | | |
| | | | | | | | | | | | |
| 43 | | Stock spares for input channel modules in the ELSAG Bailey INFI 90 | | | | | | | $8,000 | | |
| | | DCS System. (Report para. 5.6.1) | | | | | | | | | |
| | | | | | | | | | | | |
| 44 | | Replace the existing DCS System interface computer (PC) with a new | | | | | | | $4,500 | | |
| | | PC with the latest PCV and QNX software. (Report para. 5.6.1) | | | | | | | $8,000 | | |
| | | | | | | | | | | | |
| 45 | | Replace the existing obsolete DCS power supply system with a new | | | | | | | $24,000 | | |
| | | power supply. (Report para. 5.6.1) | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 46 | | Due to hot and humid conditions in the Control Building, it is | | | | | | | | | $1,000 | | | | |
| | | recommended that an air conditioning unit be installed in the area of | | | | | | | | | | | | | |
| | | the DCS equipment. (Report para. 5.6.1) | | | | | | | | | | | | | |
| 47 | | Replace the obsolete vibration monitoring system. (Report para. 5.6.3) | | | | | | | | | $20,000 | | | | |
| 48 | | Replace the existing obsolete vibration transducers with new | | | | | | | | | | | | | |
| | | accelerometers. (Report para. 5.6.3) | | | | | | | | | | | | | |
| 49 | | Replace the existing terminal blocks for thermocouple terminations | | | | | | | | | $600 | | | | |
| | | with terminal blocks designed for thermocouple use. (Report para. 5.6.4) | | | | | | | | | | | | | |
| 50 | | Install a low level cut out switch in the oil storage tank as a backup | | | | | | | | | $2,500 | | | | |
| | | to the level transmitter. (Report para. 5.6.9) | | | | | | | | | | | | | |
| 51 | | Relocate the on-engine electrical junction boxes off the engines to | | | | | | | | | $1,500 | | | $70,100 | |
| | | isolate the terminations from vibration and heat. (Report para. 5.6.12) | | | | | | | | | | | | | |
| **11--** | | **Buildings** | | | | | | | | | | | | | |
| 52 | | Control Building Refurbishments: (Report para. 5.7.1) | | | | | | | | | | | | | |
| | | o The exterior of the Building be cleaned of corrosion, prepared and | | | | | | | | | $ 11,000 | | | | |
| | | re-coated within next 2 to 5 years. | | | | | | | | | | | | | |
| | | o Install a new sloped roof over the existing flat roof for water | | | | | | | | | $ 7,000 | | | | |
| | | tightness purposes. | | | | | | | | | | | | | |
| 53 | | Fuel Unloading Building Refurbishments: (Report para. 5.7.2) | | | | | | | | | | | | | |
| | | o Replace the roof of the Building within next 2 years. | | | | | | | | | $ 5,000 | | | | |
| | | o Pave the area surrounding the concrete off-loading containment | | | | | | | | | $ 1,200 | | | | |
| | | dyke to facilitate the clean up of any spills. | | | | | | | | | | | | | |
| | | o The timber posts and guardrail protecting the concrete off-loading | | | | | | | | | $ 1,000 | | | | |
| | | dyke and piping should be replaced. | | | | | | | | | | | | | |
| 54 | | Fuel Forwarding Building Refurbishments: (Report para. 5.7.3) | | | | | | | | | | | | | |
| | | o Clean the roof, remove corrosion and repaint within 1 year. | | | | | | | | | $ 3,000 | | | | |
| | | o Clean the roof, remove corrosion and repaint within 1 year. | | | | | | | | | $ 1,500 | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | o The timber posts and guardrail protecting the Building should | | | | | | | | | | | | | | | |
| | | be replaced. | | | | | | | | | | | | | | | |
| 55 | | Auxiliary Module Building Refurbishments: (Report para. 5.7.4) | | | | | | | | | | | $ | 2,500 | | | |
| | | o Clean the roof, remove corrosion and repaint within 1 year. | | | | | | | | | | | | | | | |
| 56 | | Maintenance and Parts Storage Building Refurbishments: | | | | | | | | | | | | | | | |
| | | (Report para. 5.7.5) | | | | | | | | | | | $ | 5,000 | | | |
| | | o Clean the roof, remove corrosion and repaint within the next 2 years. | | | | | | | | | | | | | | | |
| 57 | | High Voltage Switchgear Building Refurbishments: (Report para. 5.7.6) | | | | | | | | | | | $ | 4,500 | | | |
| | | o Clean, remove surface corrosion and re-coat the exterior walls of | | | | | | | | | | | | | | | |
| | | the Building within the next 5 years. | | | | | | | | | | | $ | 3,000 | | | |
| | | o Install a new roofing system such as a modified bitumen roofing | | | | | | | | | | | | | | | |
| | | membrane applied with hot asphalt directly over the existing roof | | | | | | | | | | | | | | | |
| | | to ensure water tightness. | | | | | | | | | | | | | | $ | 44,700 |
| **12--** | | **Miscellaneous Work on Ongoing Operational Issues** | | | | | | | | | | | | | | | |
| 58 | | A number of ongoing operational issues were identified by HYDRO | | | | | | | | | | | | $250,000.00 | | | $250,000.00 |
| | | personnel during the Study. It was not possible to provide detailed | | | | | | | | | | | | | | | |
| | | solutions to these issues during the Study due to schedule and budget | | | | | | | | | | | | | | | |
| | | constraints. It is recommended that HYDRO, as part of the overall | | | | | | | | | | | | | | | |
| | | refurbishment works, include money to address these issues. A figure | | | | | | | | | | | | | | | |
| | | of $250,000 is proposed. | | | | | | | | | | | | | | | |
| | | | | | | | | **SUB-TOTAL:** | | | | | | | | $ | 4,118,870 |
| | | | | | **HYDRO labour & overhead costs for Items A - K** | | | | | | | | | | | $ | 329,510 |
| | | | | | **at 8% of Sub-total:** | | | | | | | | | | | | |
| **13--** | | **Spare Parts -- (Common To both Sites)** | | | | | | | | | | | | | | | |
| 59 | | It is recommended that HYDRO stock the following spare parts to | | | | | | | | | | | | | | | |
| | | increase the overall reliability of the Gas Turbine: | | | | | | | | | | | | | | | |
| | | **Quantity** | | **Device** | | | | | | | | | | | | | |
| | | -1- | o | Fuel Injection Nozzles (spare set) | | | | | | | | | | $16,500.00 | | | |
| | | -1- | o | Spare Starter Assembly | | | | | | | | | | $12,000.00 | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -1- | o | Spare Glycol Circulation Pump Set | | | | | | $2,000.00 | | |
| | | -1- | o | Spare 3-way Glycol Mixing Valve | | | | | | $14,000 | | |
| | | -1- | o | Spare Pressure Control Valve for Lube oil System | | | | | | $6,000 | | |
| | | -1- | o | Spare Control Valve for Fuel Oil System | | | | | | $6,000 | | |
| | | -1- | o | Install the facility for hook-up of a rental compressor. | | | | | | $2,000 | | $58,500.00 |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | **TOTAL:** | | | | **$ 4,506,880** |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |

# COST ESTIMATE SPREADSHEET No. 2
# STEPHENVILLE GAS TURBINE FACILITY
# REFURBISHMENT RECOMMENDATIONS

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Newfoundland and Labrador Hydro** | | | | | | | | | | | | |
| **Stephenville and Hardwoods Gas Turbine Condition Assessment Study** | | | | | | | | | | | | |
| **NG Job No. 21061** | | | | | | | | | | | | |
| **Rev 1 ------ 2007-12-14** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | **COST ESTIMATE SPREADSHEET No. 2** | | | | | | | | | | |
| | **STEPHENVILLE GAS TURBINE REFURBISHMENT RECOMMENDATIONS** | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **Item** | | **Stephenville Recommendations** | | | | | | | | **Cost Total** | | |
| | | | | | | | | | | | | |
| **1--** | | **Gas Generators / Power Turbines Equipment** | | | | | | | | | | |
| | | | | | | | | | | | | |
| 1 | | Engine A assembly be removed, disassembled to allow for | | | | | | | | | | |
| | | detailed internal inspection with major refurbishments as required | | | | | | | | | | |
| | | (Report para. 6.2.1) | | | | | | | | | | |
| | | o S&S Turbines Cost to refurbish and test engine assembly in BC | | | | | | | | $505,000.00 | | |
| | | o Cost to transport engine assembly to BC & back | | | | | | | | 2,600.00 | | |
| | | o Engine removal & reinstallation by S&S Turbines Technicians | | | | | | | | 14,000.00 | | |
| | | | | | | | | | | | | |
| 2 | | Engine B assembly be removed, disassembled to allow for | | | | | | | | | | |
| | | detailed internal inspection with major refurbishments as required | | | | | | | | | | |
| | | (Report para. 6.2.1) | | | | | | | | | | |
| | | o S&S Turbines Cost to refurbish and test engine assembly in BC | | | | | | | | $350,000.00 | | |
| | | o Cost to transport engine assembly to BC & back | | | | | | | | 2,600.00 | | |
| | | o Engine removal & reinstallation by S&S Turbines Technicians | | | | | | | | 14,000.00 | | |
| | | | | | | | | | | | | |
| 3 | | Inspect the Power Turbine assemblies A & B in detail upon removal of | | | | | | | | $120,000.00 | | |
| | | the Engines as noted in Items 1 & 2 to verify the mechanical integrity | | | | | | | | | | |
| | | of the units. Inspect and refurbish the following: (Report para. 6.2.5) | | | | | | | | | | |
| | | o Main line bearings inspection | | | | | | | | | | |
| | | o Remove turbine blades and perform metallurgical sampling to | | | | | | | | | | |
| | | verify alloy composition and wear to the blade roots | | | | | | | | | | |
| | | o Remove turbine disks and perform metallurgical sampling to verify | | | | | | | | | | |
| | | alloy composition and creep growth. | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | o Apply anti-corrosion/thermal protection coatings to the turbine | | | | | | | | | | | | | |
| | | blades and nozzles. | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 4 | | Completely disassemble and inspect the Power Turbine Clutches A & B. | | | | | | | | | | | $13,000.00 | | |
| | | (Report para. 6.2.6) | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 5 | | Spare Item | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 6 | | Spare Item | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 7 | | It is recommended that HYDRO replace the following obsolete | | | | | | | | | | | | | |
| | | auxiliary components with components of current design: | | | | | | | | | | | | | |
| | | (Report para. 6.2.2) | | | | | | | | | | | | | |
| | | **Quantity** | | **Device** | | | | | | | | | | | |
| | | | o | Replace Ignition Exciters | | | | | | | | | $24,000.00 | | |
| | | | o | Replace Speed Governors/fuel valve assemblies | | | | | | | | | $56,000.00 | | |
| | | | | | | | | | | | | | | | |
| 8 | | **Option:** | | | | | | | | | | | | | |
| | | S&S Turbines provides a rental engine for the period when an engine | | | | | | | | | | | | | |
| | | leaves site for refurbishment in BC until its return to site (estimated at | | | | | | | | | | | | | |
| | | 120 days per engine - assumes only one engine off-site at any time) | | | | | | | | | | | | | |
| | | o 120 days per engine x 2 = 240 days (8 months) | | | | | | | | | | | | | |
| | | o Fee for installation and removal = $14,000.00 | | | | | | | | | | | | | |
| | | o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00 | | | | | | | | | | | | | |
| | | o Fired hour charge = $42.00 per hour | | | | | | | | | | | | | |
| | | (Assume 60 hours in 8 months = $2,520.00) | | | | | | | | | | | | | |
| | | o Return transport from/to BC = $5,200.00 | | | | | | | | | | | | | |
| | | | | | | | | | | **Total:** | | | $41,320.00 | | $1,142,520.00 |
| | | | | | | | | | | | | | | | |
| **2--** | | **Inlet Air Systems A & B** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 9 | | Interior of both Inlet Air Plenums A and B and silencers be sand | | | | | | | | | | | $ 18,000 | | |
| | | blasted and recoated (Report para. 6.2.3) | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 10 | | The concrete slab of Air Plenums A & B be cleaned, prepared and | | | | | | | | | | | $ 1,800 | | |
| | | coated with breathable masonry paint (Report para. 6.2.3) | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | Re-align the inlet bellmouth assembly on Engine B | | | | | | | | | $5,000 | | | | |
| | | (Report para. 6.2.3) | | | | | | | | | | | | | |
| 12 | | Replace the rubber sealing strips around the exterior door in Inlet | | | | | | | | | $ 1,500 | | | | |
| | | Air Plenum A (Report para. 6.2.3) | | | | | | | | | | | | | |
| 13 | | Complete following items regarding the access doors to both Air | | | | | | | | | | | | | |
| | | Plenum structures: (Report para. 6.2.3) | | | | | | | | | | | | | |
| | | o Sand blast and coat all areas corroded under the access doors | | | | | | | | | $ 700 | | | | |
| | | o Weld new plates inside the troughts | | | | | | | | | $ 600 | | | | |
| | | o Replace the weather stripping on the access doors | | | | | | | | | $ 1,000 | | | | |
| | | o Install a new drip cap over both access doors | | | | | | | | | | | | | |
| | | | | | | | | | | | $ 3,400 | | | | |
| 14 | | Replace grating on platforms attached to both Air Plenum structures | | | | | | | | | | | | | |
| | | (Report para: 6.2.3) | | | | | | | | | | | | | |
| 15 | | Install new 42" high handrail with kick plates around the perimeter | | | | | | | | | $ 2,200 | | | | |
| | | of the top of each Air Plenum structure. (Report para. 6.2.3) | | | | | | | | | | | | | |
| 16 | | Weld new plates with proper size holes to existing structures to | | | | | | | | | $ 500 | | | | |
| | | prevent pullout of bolts during lifting. (Report para. 6.2.3) | | | | | | | | | | | | $ | 34,700 |
| **3--** | | **Exhaust Stacks A & B** | | | | | | | | | | | | | |
| 17 | | Install kick plates along with additional top rails to extend the height | | | | | | | | | $ 2,000 | | | | |
| | | of the existing handrails to 42" on the platforms attached to both | | | | | | | | | | | | | |
| | | Exhaust Stacks (Report para. 6.2.4) | | | | | | | | | | | | | |
| 18 | | Replace metal mesh floor grating on the Exhaust Stacks | | | | | | | | | $ 3,400 | | | | |
| | | platforms with standard bar grating (Report para. 6.2.4) | | | | | | | | | | | | | |
| 19 | | Replace existing access hatches on the Exhaust Stacks with | | | | | | | | | $ 16,500 | | | | |
| | | operable man doors with proper flashings and weather stripping | | | | | | | | | | | | | |
| | | (Report para. 6.2.4) | | | | | | | | | | | | | |
| 20 | | Modify existing snow door access platforms to support new ladders | | | | | | | | | $ 15,000 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | that will provide operators with better access to inspect the snow | | | $ | 36,900 |
| | doors (Report para. 6.2.4). | | | | |
| | | | | | |
| **4--** | **Glycol Cooler for Main Lube Oil** | | | | |
| | | | | | |
| 21 | Refurbish Glycol Cooler for Main Lube Oil as follows: | | | | |
| | (Report para. 6.2.9) | | | | |
| | o Replace bottom section of the heat exchanger | $ | 3,500 | | |
| | o Replace the canopy cladding and re-coat the entire structure | $ | 4,000 | | |
| | o Clean Tubes in Heat Exchanger to remove surface coating of | | $2,500 | | |
| | grey substance. | | | $ | 10,000 |
| | | | | | |
| **5--** | **Gas Generator / Power Turbine Enclosures A & B** | | | | |
| | | | | | |
| 22 | Interior of both Gas Generator / Power Turbine Modules A and B be | $ | 11,000 | | |
| | cleaned, areas with corrosion sandblasted and the interior of the | | | | |
| | Modules be re-coated. (Report para. 6.2.10) | | | | |
| | | | | | |
| 23 | Replace or modify the railings on top of the Gas Generator / Power | $ | 500 | | |
| | Turbine Modules for safety reasons. The new railings should be 42" | | | | |
| | high with a handrail, mid-rail and kick-plate. (Report para. 6.2.10) | | | | |
| | | | | | |
| 24 | Modify the existing man doors to both Power Turbine Modules to | $ | 1,600 | | |
| | have inspection windows added. (Report para. 6.2.10) | | | | |
| | | | | | |
| 25 | Add an additional top rail to the handrail on the stair landing for the | $ | 1,500 | | |
| | Gas Generator / Power Turbine Modules to extend the height to 42" | | | | |
| | and add kick plates to the bottom of the handrails. All for safety | | | | |
| | reasons. (Report para. 6.2.10) | | | | |
| | | | | | |
| 26 | Weld new plates with proper size holes to existing structures to | $ | 3,700 | | |
| | prevent pullout of bolts during lifting. (Report para. 6.2.10) | | | $ | 18,300 |
| | | | | | |
| **6--** | **Fire Detection and Protection** | | | | |
| | | | | | |
| 27 | Install an Inergen fire suppression system in the Control Building | | $45,000 | | |

| | | | | |
|---|---|---|---|---|
| | (Report para. 6.2.11) | | | 45000 |
| | | | | |
| **7--** | **Alternator & Excitation System** | | | |
| | | | | |
| 28 | Conduct Electrical Tests on the Alternator and Exciter while in its | $7,000.00 | | |
| | enclosure to determine condition as follows: (Report para. 6.3.3) | | | |
| | o Alternator Stator EL-CID Test | | | |
| | o Alternator Stator Polarization Index Test | | | |
| | o Alternator Stator Partial Discharge Test | | | |
| | o Alternator Rotor Megger Test - 500 vdc | | | |
| | o Measure Alternator Rotor Winding Resistance | | | |
| | o Rotating Exciter Stator and Rotor Megger Tests | | | |
| | o Measure Rotating Exciter Stator and Rotor Winding Resistance | | | |
| | | | | |
| 29 | Remove & replace the Alternator from its Enclosure and remove the rotor fo | $50,000.00 | | |
| | for complete visual inspection of the stator / rotor / exciter. Inspections | | | |
| | shall include: (Report para. 6.3.3) | | | |
| | | | | |
| | Stator Inspection to include but not limited to: | | | |
| | o Loose or damaged Wedges | | | |
| | o Loose or cracked or failed winding connections | | | |
| | o Dusting, greasing and other signs of windings movement | | | |
| | o Indications of arcing (hot spots) and damaged core laminations | | | |
| | o Loose core bolts | | | |
| | o Signs of corrosion, contamination and excessive dirt | | | |
| | | | | |
| | Rotor Inspection to include but not limited to: | | | |
| | o Signs of physical damage | | | |
| | o Loose or cracked or failed winding connectors | | | |
| | o Slot wedge migration and possible contact with retaining rings | | | |
| | o Signs of overheating | | | |
| | o Loose rotor wedges | | | |
| | o Dye penetrant examinations and magnetic particle tests on | | | |
| | forgings; retaining rings and fan components to detect | | | |
| | fatigue cracks. | | | |
| | | | | |
| | Bearings Inspection to include but not limited to: | | | |

| | | | | |
|---|---|---|---|---|
| | o Assess general condition of the bearings | | | |
| | o Determine if the bearings require re-babbiting or machining. | | | |
| | | | | |
| 30 | Carry out refurbishment work as required following following | | | |
| | completion of electrical tests (Item 27) and visual inspections. | | | |
| | (Item 28). Estimate includes: | | | |
| | o Rewind of stator at supplier's shop | $1,200,000.00 | | |
| | o Rewind of rotor c/w new end caps and overspeed testing at | $800,000.00 | | |
| | supplier's shop | | | |
| | o Rewind /refurbishment of exciter | $25,000.00 | | |
| | o Transport costs to/from supplier's shop - assume UK | $30,000.00 | | |
| | | | | |
| 31 | Perform a trim balance on the rotor to address the vibration issue | $10,000.00 | | |
| | observed physically and noted on the vibration monitoring system. | | | |
| | | | | |
| 32 | Replace the AVR control system with an ABB Unitrol F Series | $225,000.00 | | |
| | System as was done at Hardwoods. (Report para. 6.3.4) | | | $2,347,000.00 |
| | | | | |
| **8--** | **Alternator Enclosure** | | | |
| | | | | |
| 33 | Install 42" handrails on the north and south sides of the alternator | $ 1,500 | | |
| | enclosure roof for fall protection purposes. (Report para. 6.3.7) | | | |
| | | | | |
| 34 | Add inspection windows to the man doors in the alternator module | $ 1,600 | | |
| | for safety purposes. (Report para. 6.3.7) | | | |
| | | | | |
| 35 | Add an additional top rail on the handrails on the stair landings for | $500 | | |
| | the alternator module to increase the height of the handrails to 42" | | | |
| | for safety purposes. As well kickplates should be added to the | | | |
| | bottom of the handrails. (Report para. 6.3.7) | | | $ 3,600 |
| | | | | |
| **9--** | **Alternator Air Cooling System & Glycol Cooler** | | | |
| | | | | |
| 36 | Glycol Cooler be refurbished as follows: (Report para. 6.3.8) | | | |
| | o Heat exchanger support system be re-coated | $ 9,500 | | |
| | o Remove existing cladding and replace with heavy guage steel | $ 5,500 | | |

| | | |

| | | |

| | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 58 | | Waste Oil Storage Shed Refurbishments: (Report para. 6.7.4) | | | | | | | | | | |
| | | o Replace existing shed with a new non-combustible structure | | | | | | | | $ 7,900 | | |
| | | such as a new steel transportation container. | | | | | | | | | | |
| | | o Relocate the new structure to inside the oil storage containment | | | | | | | | $ 7,000 | | |
| | | dyke area. | | | | | | | | | | 74400 |
| | | | | | | | | | | | | |
| **14--** | | **Miscellaneous Work on Ongoing Operational Issues** | | | | | | | | | | |
| 59 | | A number of ongoing operational issues were identified by HYDRO | | | | | | | | $250,000.00 | | $250,000.00 |
| | | personnel during the Study. It was not possible to provide detailed | | | | | | | | | | |
| | | solutions to these issues during the Study due to schedule and budget | | | | | | | | | | |
| | | constraints. It is recommended that HYDRO, as part of the overall | | | | | | | | | | |
| | | refurbishment works, include money to address these issues. A figure | | | | | | | | | | |
| | | of $250,000 is proposed. | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | **SUB-TOTAL:** | | | | | 4202670 |
| | | | | | | | | | | | | |
| | | | | | **HYDRO labour & overhead costs for Items A - M** | | | | | | | 336213.6 |
| | | | | | **at 8% of Sub-total:** | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | **TOTAL:** | | | | **4538883.6** |

# COST ESTIMATE SPREADSHEET No. 3
# HARDWOODS & STEPHENVILLE GAS TURBINE FACILITIES
# MAJOR EQUIPMENT REPLACEMENT OPTIONS

**Newfoundland and Labrador Hydro**
**Stephenville and Hardwoods Gas Turbine Condition Assessment Study**
**NG Job No. 21061**
**Rev 1 ------ 2007-12-14**

## COST ESTIMATE SPREADSHEET No. 3

## HARDWOODS & STEPHENVILLE GAS TURBINES MAJOR EQUIPMENT REPLACEMENT OPTIONS

| Item | Major Equipment Options | Cost Total |
|---|---|---|
| **1--** | **New Gas Turbine to replace entire existing GT at one site** | $35.000,000.00 |
| | (Report para. 7.4) | |
| | o New 50 MW GT c/w synchronous condenser capability | |
| | o Includes all new mechanical auxiliary equipment | |
| | o New fuel forwarding module | |
| | o New Air Compressor Package | |
| | o New lube oil system | |
| | o Includes all new electrical auxiliary equipment | |
| | o New 13.8 kV switchgear / motor control centres / batteries&chargers / | |
| | digital protection relays / bus duct / cabling / motors | |
| | o New station service transformer | |
| | o Includes all new control & instrumentation auxiliary equipment | |
| | o New DCS Control System | |
| | o New vibration monitoring system | |
| | o New temperature monitoring system | |
| | o New Instrumentation Devices throughout | |
| | o Requires a new concrete foundation for GT | |
| | o Includes installation and commissioning | |
| | o Allowance for HYDRO engineering staff involvement in new gas turbine | 400,000.00 |
| | procurement and installation. | |
| | **Sub-Total:** | **$35,400,000.00** |
| | o Allowance for Dismantling the existing Gas Turbine and the Demolition of | **$1,500,000.00** |
| | surplus buildings and structures | |
| | **Total:** | **$36,900,000.00** |

| | | | |
|---|---|---|---|
| | | o Retain existing fuel oil storage tanks and truck unloading equipment | |
| | | o Retain existing step up transformer | |
| | | o Review role of existing buildings at each site | |
| | | o Requires new physical location at site (old GT not removed) | |
| | | | |
| | | | |
| **2--** | | **New alternator and rotating exciter at one site** | |
| | | (Report para. 7.3.2) | |
| | | o Purchase new alternator and exciter c/w new AVR | $2,500,000.00 |
| | | o Top mounted standard air filter house | $300,000.00 |
| | | o Acoustic and weather protection canopy | $250,000.00 |
| | | o Installation & Commissioning (estimate) | $750,000.00 |
| | | o Transportation Costs | $75,000.00 |
| | | o Interface costs to existing infrastructure & auxiliary systems (estimate) | $1,000,000.00 |
| | | o Carry out other refurbishment work at each site in accordance with | $2,288,381.00 |
| | | Spreadsheets No. 1 and 2 (See Report para. 7.3.2) | |
| | | **Total:** | **$7,163,381.00** |
| | | | |
| | | | |
| **3--** | | **New gas generators (engines) and power turbines for one site** | |
| | | **(MAN TURBO Proposal -- $Cdn)** (Report para. 7.3.1) | |
| | | | |
| | | o Purchase 2 new gas generators & 2 new power turbines | $20,900,000.00 |
| | | o Transportation to site | 200,000.00 |
| | | o Erection and Commissioning | 2,000,000.00 |
| | | | |
| | | o Carry out other refurbishment work at each site in accordance with | $3,319,761.00 |
| | | Spreadsheets No. 1 and 2 (See Report para. 7.3.1) | |
| | | | |
| | | **Sub-Total:** | **$26,419,761.00** |
| | | o Modifications to existing engine/power turbine enclosures as required | To be advised |
| | | to accommodate new equipment | pending further study |
| | | | |
| | | **Total:** | **To be Advised** |
| | | | |
| | | | |
| **4--** | | **Rental of temporary mobile gas turbines for one site** | |

| | | | |
|---|---|---|---|
| | | (To provide required MW and MVAR service while alternator is being | |
| | | refurbished or replaced) (Report para. 7.5) | |
| | | | |
| | **(i)** | **o Pratt & Whitney 25 MW MobilePac gas turbine (4 month rental)** | |
| | | o Transportation to Site from Europe | $625,000.00 |
| | | o Site Set up Fee | 150,000.00 |
| | | o HV Connection | 50,000.00 |
| | | o Fuel Connection | 7,500.00 |
| | | o Monthly Rental = $400,000 per month | 1,600,000.00 |
| | | o Full Time Supervisor = $25,000 per month | 100,000.00 |
| | | o Site Dismantle Fee | 150,000.00 |
| | | o Transportation Back to Europe | 625,000.00 |
| | | **Total:** | **$3,307,500.00** |
| | | | |
| | **(ii)** | **o Caterpillar 5 MW gas turbine (4 month rental)** | |
| | | o Rent 5 machines = 25 MW capacity | |
| | | o Monthly rental cost (capacity charge) per gas turbine = $105,000 | $2,100,000.00 |
| | | o Fired Hours Charge per gas turbine = $42.00 per hour | $42,000.00 |
| | | (Assume 1000 hour total for 4 months) | |
| | | o Mobilization & Consumables Cost per gas turbine = $16,000 | $80,000.00 |
| | | o Setup, Commissioning & Test per gas turbine = $106,000 | $530,000.00 |
| | | o Decommissioning per gas turbine = $48,500 | $242,500.00 |
| | | o Full Time Site Supervisor at $10,000 per month | $40,000.00 |
| | | **Sub-Total:** | $3,034,500.00 |
| | | | |
| | | o Connect 5 machines to existing 13.8 kV circuit breaker | $50,000.00 |
| | | and step-up transformer (estimate) | |
| | | o Connect existing fuel line to rental GT's | $7,500.00 |
| | | **Total:** | **$3,092,000.00** |
| | | | |
| | | | |
| **5--** | | **Dynamic Var Compensator at Hardwoods Site only** | |
| | | (To replace the Hardwoods Gas Turbine) (Report para. 7.6) | |
| | | **o High level ballpark estimate** | $10,000,000.00 |
| | | o Purchase new 30 MVAR dynamic var compensator equipment | |
| | | o Includes civil site costs - preparation & concrete works | |
| | | o Includes terminal station bus work | |
| | | o Retain existing 13.8 / 138 kV step-up transformer | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | o Retain existing 13.8 kV switchgear assembly | | | | | | | | | | |
| | | o Dismantling costs of existing gas turbine | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | *This is a ballpark estimate only. If HYDRO is interested in pursuing this option* | | | | | | | | | | |
| | | *an indepth study with involvement by a D-VAR supplier is required to* | | | | | | | | | | |
| | | *investigate the application of this technology at the site, define scope and confirm costs.* | | | | | | | | | | |

# APPENDIX 7
# MAN TURBO NEW ENGINES AND POWER TURBINES PROPOSAL

**Hearn, Bill G.**

**Subject:** FW: 50 MW Gas Turbine Generator/Synchronous Condenser

**Attachments:** N&G_TechQuotation.pdf; Ref_FT8(worldwide).pdf; FT8 Power Key to Plant Upgrade.pdf; Integration of 25MW gt into existing power Station.pdf; MOBILEPAC.pdf; Mobile Power Paper1.doc; Two containerized 22.8 MW TM2500 gt powered gensets.jpg; FT8MobilePac_PEi (Oct2007).pdf

**From:** Pierre Bovon [mailto:Pierre.Bovon@manturbo-us.com]
**Sent:** Friday, November 02, 2007 2:28 PM
**To:** King, Brian
**Subject:** RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

As per our discussions, we understand that the tasks at hand can be split into basically 4 steps:

1. Provide replacement FT-8 engines for the existing Curtis-Wright gas turbines located at the Hardwood station. We can offer 2 x FT8-30 gas turbines designed for Diesel fuel, on baseplates, complete with auxiliary systems such as lube-oil system, CAB-system, standstill dryer, fire and CO2 protection, control panel, MCC, etc... Excluded are filter house, exhaust system, acoustic enclosure, or modifications thereof, dual fuel system with water injection, generator/synchronous condenser with auxiliaries, SSS couplings, etc... For this scope, we would estimate a cost of approx US$ 15 million for the US portion, plus Euro 5 million, for the European portion, FOB European port. Erection and commissioning would obviously depend on the local conditions, but we would estimate somewhere in the US$ 2 million range. See attached Technical Quotation.
2. The same would apply to Stephenville, unless you decide to use the gas turbines you pulled out from Hardwood as a source of spares to keep the currently installed units running at the Stephenville station. We would also point out that to our knowledge there is a second-hand market for parts for these engines which were used extensively used on war ships like destroyers and frigates.
3. At both stations, while back-up interim power is available (see point 4 below), Brush would have plenty of time to inspect and overhaul the installed generator/synchronous condenser and put them back into service. Or a replacement unit could be supplied for Hardwood to permit this same unit moved to Stephenville after overhaul.
4. Provide interim power at the Hardwood site for the duration of the upgrading work to be a carried out on the current power station. The same unit(s) could then be moved to Stephenville during the upgrading of that station. As you can see from the attached documents, standard portable stand-by gensets are readily available for sale, or may be even for rental, from Pratt & Whitney (FT-8) or from GE (LM 2500). MAN TURBO would not necessarily get involved in this aspect of the project. A number of documents dealing with these mobile units are attached.

We trust you will understand that if this develops into a concrete project, MAN TURBO would like to be given a chance to participate, and that we are currently quoting and executing similar projects in other parts of the world, as can be seen from the various attachments.
Hopefully the attached information will be useful for the time being.

Kind regards, Pierre

Pierre L. Bovon

MAN TURBO, Calgary
Suite 700,
1816 Crowchild Trail NW
Calgary, AB, T2M 3Y7

Tel. (403) 233-7151

Fax (403) 220-1389

E-mail: pierre.bovon@ca.manturbo.com or pierre.bovon@manturbo-us.com

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---

**From:** King, Brian [mailto:Brian.King@stantec.com]
**Sent:** Wednesday, October 24, 2007 12:26 PM
**To:** Pierre Bovon
**Subject:** RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Thanks for this up-date Pierre, and for your voice-mail earlier today. We too are talking with Brush to see what options we can explore for repairing/replacing the alternators. There is an important point to note: the alternator at Stephenville is slightly longer than the one at Hardwoods! This is to cater to the use of a glycol/water mix to cool the alternator at Stephenville, and this calls for increased surface in the alternator air path.

There is another concern that will effect selection of a particular option, and that is the duration of alternator down-time. It may not be practical to implement repairs to the existing units because the power distribution system needs their availability almost daily. It is therefore important to know how much it would cost to install a new unit and retain the existing plant. The operating philosophy would be to monitor the condition of the insulation in the existing units and to use them for synchronous condenser operation. The new units could be more conventional turbo-gen sets that are permanently coupled. They could be operated as synchronous condensers but with the penalty of wasted energy for driving the power turbine as a windmill. This type of operation would only be necessary to cover the time needed to up-grade and reinstate the old alternators.

Regards, Brian

---

**From:** Pierre Bovon [mailto:Pierre.Bovon@manturbo-us.com]
**Sent:** Tuesday, October 23, 2007 6:15 PM
**To:** King, Brian
**Subject:** FW: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

We have contacted Brush who supplied the original generator/synchronous condenser around 1975 (see drawing attached). Here is the technical information they provided.

BDAX8-280 13.8kV/3/60Hz
53.84MW/63.34MVA 0.85PF 3600rpm
ANSIC50.13 15 Deg C Air Inlet
2 off Double End Drive

Turbine Rating

-10 Deg F - 58.8MW
0 Deg F - 58.8MW
10 Deg F - 58.8MW
20 Deg F - 58.8MW
40 Deg F - 56.2MW
59 Deg F - 53.84MW
80 Deg F - 50MW
90 Deg F - 48MW

Suitable for -23 Deg C cold start

Supplied for use with SSS Clutch type 208T, with housings?

Design / size of machine we would now supply is different but we could offer a "interchangeable" / replacement unit.

MAN TURBO is of the opinion that replacement may not be necessary and that an overhaul may be sufficient. According to our experience, these electric machines are subject to much less wear than a GT, and that upgrading of the insulation and other minor repair may be sufficient to keep the unit running for years.

I will try to get a ball park figure for the replacement for you.

Kind regards, Pierre

Pierre L. Bovon

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Calgary, AB, T2M 3Y7

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**From:** Pierre Bovon
**Sent:** Thursday, October 18, 2007 11:19 AM
**To:** 'King, Brian'
**Subject:** RE: 50 MW Gas Turbine Generator/Synchronous Condenser

Hello Brian,

I acknowledge receipt of your huge file which I could not pass on as received. I sent it on to Germany by CD. I will however attempt to give you some useful information for now.
Technical:
As I explained to you, the FT-8 may be quite suitable as a replacement for these Curtiss Wright machines. Without in-depth investigation, we cannot tell so far whether the current acoustic enclosure and the exhaust housing could be modified to accommodate this substitution. We understand that the new units would have to be installed starting at both end from the SSS coupling. A somewhat similar solution was proposed for another installation (OLKILUOTO, see drawing enclosed), where spacer shafts were installed at one end, and where exhaust channels were built to the chimneys. As another example, you will find the drawing of the installation FINNJET, which was a retrofit of an FT-8 in place of an FT-4.
Commercial:
We can advance the following rough estimates: 2 x FT8-30 gas turbines designed for Diesel fuel, on baseplates, complete with auxiliary systems such as lube-oil system, standstill dryer, fire and CO2 protection, control panel, MCC, etc... without filter house, exhaust system, acoustic enclosure, or modifications thereof, we would count with a cost of approx US$ 24 million, FOB European port. Erection and commissioning would obviously depend on the local conditions, but we would estimate somewhere in the US$ 2 million range.
Current deliveries are quite long, probably in the range of about 18 months ex-works.

I hope the above information is useful for the current level of estimates that you have to prepare. If you require additional data, please do not hesitate to came back to me.

Kind regards, Pierre

Pierre L. Bovon

MAN TURBO, Calgary
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Calgary, AB, T2M 3Y7

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**From:** King, Brian [mailto:bking@NGNS.com]
**Sent:** Friday, September 28, 2007 11:59 AM
**To:** Pierre Bovon
**Subject:** FW: 50 MW Gas Turbine Generator/Synchronous Condenser

---

**From:** King, Brian
**Sent:** Friday, September 28, 2007 10:58 AM
**To:** 'pierrebovon@manturbo.com'
**Subject:** FW: 50 MW Gas Turbine Generator/Synchronous Condenser

This is a repeat of previous attempts to e-mail you.
Brian

---

**From:** King, Brian
**Sent:** Friday, September 07, 2007 4:27 PM
**To:** 'pierrebovon@ca.manturbo.com'
**Subject:** 50 MW Gas Turbine Generator/Synchronous Condenser

Pierre Bovon,
Thanks for your offer of help on this topic. The attachment is the Curtiss Wright Manual for the Hardwoods site that contains information on the Alternator, the general information is copied below. The existing plant has an Olympus C 25MW gas turbine fuelled with #2Fuel Oil, at each end of the Alternator. They are gas generators that feed into Curtiss Wright turbines, and these are connected through SSS Clutch mechanisms to the alternator.

My guess at the cost of replacement plant is in the region of $35million, what is your guess?
Regards

Brian King (bking@ngns.com)

| | | |
|---|---|---|
| First Name | : | Brian |
| Last Name | : | King |
| Organization Name | : | Neill and Gunter (Nova Scotia) Limited |
| Country | : | Canada |
| Email | : | bking@ngns.com |
| Keywords | : | 50MW Peaking Plant |
| Comment | : | 1.1 INTRODUCTION |

Newfoundland and Labrador Hydro (HYDRO) is a utility which owns and operates facilities for the generation, transformation and distribution of electricity to utility, industrial and residential customers in the Province of Newfoundland and Labrador.

In the island interconnected grid, HYDRO has nine (9) hydro-electric generating plants with a total installed capacity of 980 MW and five (5) thermal generating plants with a

total installed capacity of 626 MW. Two nominal 50MW gas turbine facilities provide peaking, emergency backup and synchronous condensing services. One facility is located at Stephenville, on the south west coast of the island of Newfoundland and the other is located at Hardwoods on the east coast near the City of St. John's.

2. DESCRIPTION

2.1 REQUIREMENT

The purpose of this request for a quotation is to provide HYDRO with a cost estimate that can be used as a basis in deciding the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years at both the Hardwoods and Stephenville gas turbine plants. The output of the replacement plants should be as close to 50MW as the standard product line will achieve. Operation of the alternator as a synchronous condenser is an important feature of the required plant(s).

2.2. AVAILABLE INFORMATION

For information purposes some general information is being provided to assist Proponents in preparing proposals.

General:

Ambient conditions, 99% > -6degF, <80degF. 50ft ASL.

This electronic document contains information that may be confidential, privileged o
The information is intended to be used solely by the recipient(s) named. If the rea
intended recipient, any disclosure, copying or distribution is prohibited. If you h
please notify us immediately at ngns@ngns.com.





Technical Quotation

# 2 (two) FT8-36 Gas Turbine Sets
# for
# Hardwood Power Station

Neill and Gunter (Nova Scotia) Limited

Canada

MAN TURBO AG
Steinbrinkstraße 1
46145 Oberhausen
Germany

**Project Manager:** Norbert P. Faustmann
Dept.: SD3
Phone: +49-208-692-2475
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E-mail: norbert.faustmann@de.manturbo.com

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# 1. IDENTIFICATION DATA

## 1.1 Background and Capabilities

In 2001, three powerful partners - GHH, BORSIG and SULZER – boasting over 180 years of experience of turbomachinery manufacture united under the MAN TURBO logo. The name is a byword for innovative know-how, commitment and creativity in the development and construction of pioneering products and technologies that set global standards, always in the service of our customers. We are thus at the forefront of international competition in this field.

Three legally autonomous core companies operate at four sites, each with their own production shops:

MAN TURBO AG
Oberhausen, Berlin, Hamburg and Deggendorf, Germany

MAN TURBO AG, Switzerland *(previously Sulzer Turbo AG),*
Zurich, Switzerland

MAN TURBO S.r.l. *(previously de Pretto-Escher Wyss, S.r.l.)*
de Pretto
Schio, Italy

The turbomachinery activities of the MAN Group are managed centrally for all three companies by MAN TURBO AG, Oberhausen-Sterkrade.

MAN TURBO offers the broadest product spectrum in the entire sector. These companies are distinguished by their high level of competence in the development and production of complete turbomachinery trains. In addition to compressors, MAN TURBO with its gas and steam turbines, and process expanders, offers a comprehensive range of prime movers, enabling our customers to obtain the sophisticated technology they require for a variety of applications from a single supplier.

MAN TURBO has taken over the steam turbine programme of B+V Industrie-technik GmbH (BVI), Hamburg in 2006. Also in 2006 MAN DWE (formerly Deggendorfer Werft und Eisenwerk GmbH), part of the MAN Group, was integrated in the MAN TURBO Group.

The MAN TURBO AG was converted into a joint stock company retroactively to July 01, 1999 and directly allocated to the MAN Group.
The former GHH BORSIG Turbomaschinen GmbH was founded as a merger of the turbomachinery divisions of MAN Gutehoffnungshütte AG of Oberhausen, and Deutsche Babcock-Borsig AG of Berlin on March 01, 1996.

Gas turbines have been included in the range of products since 1988 by absorbing the industrial gas turbine business of the French company Hispano-Suiza.

## 1.2 Gas turbine manufacturer

In 1990, the gas turbine product line was expanded by signing a cooperation agreement with Pratt & Whitney's subsidiary Pratt&Whitney Power Systems Inc. (formerly Turbo Power & Marine Systems Inc.) for developing, manufacturing, and servicing of the FT8 industrial gas turbine family. The FT8 combines most advanced technologies used in the aeroengine industry with the operating experience of well over 14,506 JT8D-type aircraft engines of Pratt & Whitney. An additional 30 years and more than 14 million operating hours of experience with the predecessor model FT4 have created a gas turbine for every application.

## 1.3 Gas turbine type

Based on the FT8 gas turbine MAN TURBO developed a „Modular Growing Standardized Power Station System" (MOGSPOSS) which allows to adapt a simple cycle power station to the customer's requirements of growing power requirements and improvement of efficiency by adding components as additional gas turbines.

## 1.4 Generator manufacturer

In the quotation are included only supplier of the two-pole generators. The generator plants are from BRUSH Electrical Machines Ltd. in Loughborough, England, UK, from Siemens AG in Erfurt, Germany, and from Jeumont Electric in Jeumont Cedex, France etc..

## 1.5 Engineering Consultant

The preferred engineering consultant of Fingrid Oy was the Finnish company ÅF-Enprima Ltd who acted for the reserve power plant project at Olkiluoto.

The other engineering consultant was also a Finnish company Poyry (formerly Electrowatt-Ekono) who acted for the emergency power plant project for Kraftnät Aland Ab at Ringsböle in the same function

## 1.6 FT8 Reference List

**Attachments**

Reference List FT8 Industrial Gas Turbine **(Later)**

## 1.7 FT8 Reference List – Installations by MAN TURBO AG

**Attachments**

Reference List FT8 Industrial Gas Turbine – Installations by MAN TURBO AG **(Later)**





## 1.8 Reference List FT8 TwinPac / SwiftPac 50

### Attachments

- Reference List of FT8 TwinPac / SwiftPac 50 **(Later)**

## 1.9 Reference List FT8 TwinPac – Installations by MAN TURBO AG

### Attachments

- Reference List of FT8 TwinPac – Installation by MAN TURBO AG **(Later)**
- FT8 TwinPac in Rheinberg/ Germany **(Later)**
- FT8 TwinPacs in Olkiluoto / Finland **(Later)**





# 2. GENERAL

## 2.1 Plant Description

On basis of our former project at Olkiluoto in Finland for a reserve power plant with a supplemental function as emergency power plant for the OL nuclear plants of TVO we are offering an indoor installation for replacing of Olympus gas turbines.

The base offer comprises of (2) two FT8-36 Gas Turbine Sets (25MW each)

MAN TURBO offers its 25 MW ISO rated gas turbine FT8-36 for power production. The FT8-36 gas turbine, designed for 60 Hz power generation via a direct driven synchronous generator, will be configured as a so-called „TwinPac", a configuration with two gas turbines driving a double-end generator. Together with the ancillary equipment, a completely self-contained package is formed, offering an outstanding efficiency in the 50 MW class gas turbine market segment.

Due to its aero-derivative design with fast start-up and quick loading capability, the FT8 industrial gas turbine is ideally suited for daily start and stop operation as well as for base load power generation, keeping the operating cost at a competitive level. The outstanding efficiency figures, based on the two-shaft design of the gas generator and the use of the latest developments in the aircraft industry, are maintained over a wide load range, making the FT8-36 TwinPac configuration a reliable and thus cost-advantageous solution for simple cycle power generation applications.

The Scope of Supply of the FT8-36 Gas Turbine Sets includes the skid-mounted gas turbine coupled to the generator on a separate baseframe, and all ancillary equipment required to form a complete package installation.

Load sharing capability is not included in the Scope of Supply as detailed information is necessary to investigate a suitable solution but can be offered at a later stage of the project if requested.

To meet the inquired noise restrictions an indoor installation is offered.

A more detailed description of the Scope of Supply and Services is contained in the following section.

## 2.2 Plant Layout





## 3. SCOPE OF SUPPLY AND SERVICES

The scope of supply includes two (2) FT8-36 Gas Turbine Sets.

The finally FT8-36 TwinPac consists of two FT8-36 gas turbine including auxiliary plant equipment and a synchronous generator with two shaft ends. The scope of supply includes the components and services listed below (listed per FT8-36 gas turbine and per Electrical generator):

### 3.1 Base frame with mounted FT8 gas turbine

**GG8 gas generator with**

- Bellmouth
- Fuel manifold, fuel nozzles
- Variable inlet guide vanes
- Variable stator vanes (stages 2 - 3)
- Compressor bleed valves
- Muscle air system for closing of bleed valves
- Auxiliary gear unit with starter motor
- Rotor speed sensors (2 x LP shaft, 3 x HP shaft)
- Vibration probe (1x LP casing)

**PT8-36 power turbine with**

- Rotor speed sensors (3 x)
- Vibration sensors (2 x PT8 casing)
- Diffuser section
- Exhaust collector box
- Output shaft with diaphragm couplings

**Ignition system**

**Fuel system**

- Shutoff valves
- Modulating valve
- Distribution system

**Hydraulic system**

**Lube oil system piping and valves**

**Measuring transducers and transmitters**

### 3.2 Lube oil skid for gas generator and power turbine

- Two 3-phase AC and one DC motor-driven pump
- Oil cooler
- Oil tank
- Heater
- Duplex filter

### 3.3 Starter skid (electro-hydraulic)

- One motor-driven hydraulic pump
- Filter
- Oil tank
- Heater

### 3.4 Inlet air system

- Air inlet plenum integrated in the gas turbine enclosure

### 3.5 Exhaust gas system

- Expansion joints
- Exhaust duct adapter

### 3.6 Set of interconnecting Piping

- Pipework (supplied loose), partially prefabricated, for interconnection of ancillary equipment with gas turbine

### 3.7 Gas turbine control panel

One in common for each TwinPac consisting of:

- three (3) sections with:

  Woodward MicroNet digital gas turbine controller,
  Bently Nevada accelerometer-based vibration monitoring System 3500,
  Siemens S7 programmable logic controller for sequencing and
  Siemens WIN-CC monitoring system with VDU-screen.

- two (2) marshalling sections with:

  terminal strips for all incoming and outgoing signal cables

The control panels of the gas turbines or/and the electrical generator, of the MCC distribution board and DC supply, and the control panel for the fire fighting and detection systems are to be housed direct in Customer's GT building or control room.

## 3.8 Engineering

- General arrangement drawing
- P&I diagrams
- Foundation size and load plans
- List of terminal points
- Cable plan
- Logic flow chart
- Terminal box wiring plan
- Control panel layout drawing
- List of electrical consumers
- Combined alarm and interlocking list
- Instrument list

## 3.9 Documentation

- 5 copies of the Operation and Maintenance Manuals

## 3.10 Test runs

Full-load test of gas generator

## 3.11 Options

Options marked with an "X" are included in the price.

| | |
|---|---|
| X | Standard combustion chamber |
| X | Mobile compressor wash system (off-line)<br>(one per site or several gas turbines) |
| X | Engine preservation system |
| . | Gas fuel system |
| X | Liquid fuel system |
| . | Dual fuel system |
| X | Gas fuel skid and filter system |
| X | Liquid fuel skid with heater and filter skid |
| . | Liquid fuel forwarding pumps and filtering skid |
| . | Water injection skid and system |
| . | Moisture separation system / Coalescer |
| . | Self-cleaning air filter system (pulse type) |
| . | Anti-icing system for inlet air system |

- Static filter system (two stage)
- **Inlet air system**
  - Air intake duct between filter house and intake silencer
  - Intake silencer to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level
- **Indoor enclosure Gas turbine enclosure**
  - Sound insulation to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level
  - Indoor enclosure
  - Lighting system
  - Hand-operated lifting tackle
  - Ventilation system with sound insulation
  - Fire fighting system
  - Fire detection system
- **Fire - Control panel**
  - Control panel of wall-mounted type for fire fighting and detection systems of gas turbine enclosure
- **Electrical generator including ancillaries**
  - synchronous generator, double-end-driven
  - Neutral point cubicle
  - Line side cubicle
  - Cooling system
- **Electrical generator control panel**
  - Excitation system (AVR)
  - Generator protective equipment
  - Instrumentation
  - Synchronizing system
- **Electrical generator lube oil skid**
  - Duplex filter
  - Oil cooler
  - Two 3-phase AC and one DC motor-driven pump

- Oil tank with heater

. **Generator enclosure**

- Sound insulation to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 / ISO 6190 at 1m distance and 1.5m height above ground level

. Outdoor enclosure

. Container for gas turbine ancillary equipment
(one for each gas turbine unit)

. Control container for outdoor installation

. Exhaust silencer to meet a sound pressure level of 85 dB(A) according to EN ISO 3746 and ISO 6190 at 1m distance and 1.5m height above ground level

. Silencers and enclosures to meet lower sound emissions

. Exhaust stack with 15m above ground level

X Motor Control Centre (MCC)
- MCC of withdrawable type for all electrical consumers in the scope of supply

X DC Battery System and Uninterruptable Power Supply (UPS)
- UPS and battery system for 230 VAC, 24/110/125 VDC power levels

. Load sharing capability for multiple engine configuration

. Set of interconnecting cables
- Interconnecting MV-cable-material and LV-power and signal cable material (supplied loose / **max. straight length 50m**) within the confines of the scope

. SSS-clutch couplings for TwinPac

. Supervision of erection and commissioning by MAN TURBO personnel

. Erection and commissioning by MAN TURBO personnel

. Supervision of trial operation (72 hours) by MAN TURBO personnel

. Training of operators by commissioning staff

. Full owner staff training given at MAN TURBO's works (See separate quotation)

. Spare parts (See separate quotation)

. Special tools (See separate quotation)

. Rental pool agreement
(gas generator, power turbine)

. Service/maintenance (See separate quotation)

Option – Outside GT Base Scope (See in Chapter 20)
- HI-FOG System
- Closed Cooling System
- Air Cooled Solutions





- Anti-Icing System with Exhaust and Sound Protection System
- Air Pressure Skid

## 3.12 Exclusions from supplies and services, requirements

All equipment and services not expressly mentioned in the foregoing sections are excluded and shall be provided free of costs by the Customer. Those supplies and services which are not part of our quotation include but are not limited to:

**General**

- All permits (e.g. planning permission), licences (e.g. approval of operation), and acceptance certificates levied by the authorities for the transport, construction and operation of the plant, unless specifically included in the scope of supply.
- All supply and return piping (fuel, injection water, drain, vent, ...) to and from the specified takeover points.
- External / internal (between skids) cables and cabling work to and from the specified takeover points including electrical connections
- The earthing system including connection to the equipment.
- Design and supply of foundations as well as all earthwork, brickwork, concrete and carpentry, cable trays.
- Industrial commissioning and other site activities (e.g. test run, acceptance test, performance test ...).

**Specific for erection and commissioning**

- **Site requirements and required services**

- A surfaced road connecting the jobsite to the nearest major road for the transportation of machine components.
- Suitable, compact area according to requirements on the works premises, near the jobsite for our construction facilities.
- The jobsite shall be secured.
- Supply of drinking water, service water and electrical power (220VAC, 63A)
- Provision of fluid system media in case hydrostatic tests are to be performed
- Liquid fuel
- Water for washing the compressor blading

- **Foundation requirements**

- Customer shall establish invariable axes and elevations approx. 3 weeks prior to start of the erection work.
- Grouting of anchor bolts/jacking plates with anti-shrinking compound (anchor bolts/jacking plates included in scope)

- Gauging of location of foundation internals and provision of gauging record approx. 3 weeks prior to start of erection work.
- All foundations ready for erection brushed clean and capable of absorbing full load, prior to the start of erection.

- **General requirements**

- Customer undertakes to inform our personnel on all obligations, notifications and similar with respect to local authorities, and to render all required assistance in dealings with such authorities.
- Time spent waiting for reasons not attributable to MAN TURBO shall be invoiced at the actual time of work on the basis of the valid MAN TURBO rates.
- Commissioning shall be performed without interruption immediately after completion of the erection operations, and is limited to three weeks. Testing of the complete plant to be performed by the Customer and MAN TURBO staff exceeding this time limit shall be invoiced at the actual time of work on the basis of the valid MAN TURBO rates, i.e. industrial machine start-up and surveillance during permanent operation shall be performed by the Customer.
- Qualified personnel for operating the plant up to the time of handing-over





## 4. BATTERY LIMITS OF LIQUID / GASEOUS MEDIA

Media to be supplied: =>
Return media to be drained, ventilated, etc: <=

| Media => | **GT combustion air** |
|---|---|
| Connection (supply) | Inlet Plenum of GT |
| Drawing no. | To follow |
| Media => | **Ventilation air for GT encloure** |
| Connection (supply) | Entrance of base frame area of GT |
| Drawing no. | To follow |

| Media => | **Natural Gas** |
|---|---|
| Specification | Fuel gas Doc. No. 10000082991 |
| Connection (supply) | flange approx. 1m from GT-enclosure |
| P&I diagram no. | To follow |
| Mass flow (normal operation) | (refer to performance data) |
| min. pressure (DLN-base load) | 31,4 bar (abs) 35,5 bar (abs) |
| max. pressure | 42,4 bar (abs) |
| protection pressure | 45,5 bar (abs) |
| min. temperature | 20 K above dew point |
| max. temperature | 149 °C |
| Media => | **Liquid fuel** |
| Specification | Fuel acc. To Doc. No. 10000082993 |
| Connection (supply) | flange at fuel forwarding skid |
| P&I diagram no. | To follow |
| Mass flow (normal operation) | (refer to performance data) |
| min. pressure | from 6m elevation about site location |
| max. pressure | 4,5 bar (abs) |
| protection pressure | 6,0 bar (abs) |
| min. temperature | Min. 15 K above cloud point |
| max. temperature | Min. 5 K below flash point and $\leq$ 70°C |

| Media => | **Water for NOx reduction and GT compressor wash** |
|---|---|
| Specification | Demineralized water acc. to Doc. No. 10000082993 |
| Connection (supply) | flange at injection skids and wash water tank on mobile wash trolley |
| P&I diagram no. | To follow |
| Mass flow (during washing) | (refer to performance data) |
| min. pressure | 3 bar (g) |
| max. pressure | 4.5 bar (g) |
| min. temperature | 5 °C |
| max. temperature | 70 °C |

| Media => | **Lubricating and hydraulic oil** |
|---|---|
| Specification | |
| GT lube and hydraulic oil: | Doc.No.10000134443 |
| GT starter hydraulic oil and | Doc.No.10000134445 |
| electrical generator lube oil: | N.A. |
| Connection (supply) | Filling plugs of the oil tanks |
| P&I diagram no. | To follow |

| Media => | **Water for air / oil cooler** |
|---|---|
| Specification | to follow |
| Connection (supply) | to follow |
| P&I diagram no. | to follow |
| Mass flow (approx.) | to follow |
| min. pressure | to follow |
| max. pressure | to follow |
| min. temperature | to follow |
| max. temperature | to follow |
| Media => | **Water for evaporative cooler** |
| Specification (approx.) | 0°dH (carbonate); 15-20 mS/m conductivity |
| Connection (supply) | flange at evaporative cooler system |
| P&I diagram no. | to follow |
| Volume flow (typical) | approx. 10m³/h per gas turbine |
| min. pressure | 2 bar (abs) |
| max. pressure | to follow |
| min. temperature | to follow |
| max. temperature | to follow |
| Media => | **Water for anti-icing (Glycol-system)** |
| Specification | to follow |
| Connection (supply) | flange of water/glycol heat exchanger |
| P&I diagram no. | to follow |
| Mass flow (approx.) | 400 l/min per gas turbine |
| min. pressure | 7 bar(g) (pumps supplied by MAN TURBO) |
| max. pressure | to follow |
| min. temperature | 150°C |
| max. temperature | to follow |

| Media <= | **Water from air / oil cooler** |
|---|---|
| Specification | to follow |
| Connection (exit) | to follow |
| P&I diagram no. | to follow |
| Mass flow (approx.) | to follow |
| min. pressure | to follow |
| max. pressure | to follow |
| min. temperature | to follow |
| max. temperature | to follow |

| Media <= | **Waste Water of evaporative cooler** |
|---|---|
| Specification | to follow |
| Connection (exit) | flange at evaporative cooler system |
| P&I diagram no. | to follow |
| pressure | to follow |
| Media <= | **Water from anti-icing (Glycol-system)** |
| Specification | to follow |
| Connection (exit) | flange of water/glycol heat exchanger |
| P&I diagram no. | to follow |
| Mass flow (approx.) | 400 l/min per gas turbine |
| pressure | 6,5 - 7 bar (g) |
| temperature | 0-150°C |

| Media <= | **Water (Drain)** |
|---|---|
| Specification | sewage to be lead into an oil carrying drain system |
| Connection (exit) | 3 flanges of drain pipes at the GT-base frame |
| P&I diagram no. | To follow |
| Pressure | ambient pressure |

| Media => | **Fire extinguishing system)** |
|---|---|
| Specification | N.A., Complete system for GT enclosure |
| P&I diagram no. | To follow |

| Media <= | **Ventilation air of GT enclosure** |
|---|---|
| Connection (exit) | Exit of base frame area of GT |
| Drawing no. | To follow |

| Media <= | **Exhaust Gas** |
|---|---|
| Connection (exit) | exit flange of exhaust collector box |
| Drawing no. | to follow (flange dimensions) |
| Mass flow (normal operation) | (refer to performance data) |
| Document no. | to follow (possible velocity/temp. distribution) |
| pressure | is determined by the pressure losses of the installations in the exhaust duct as for example exhaust silencer and stack |
| max backpressure | 50 mbar |
| max. temperature | approx. 520°C at peak load and 40°C $T_{amb}$ |

| Media <= | **Blow-off pipes** |
|---|---|
| Connection (exit) | Conducted to safe area (max length 3m) |
| P&I diagram no. | to follow |

## 4.1 Battery limits of electrical and control systems

| System | **Medium Voltage Power** |
|---|---|
| Connection | Generator terminals |
| Single line diagram no. | To follow |

| System | **Low Voltage Power** | | | |
|---|---|---|---|---|
| **Power required** | | | | |
| **FT8 TwinPac** | Start | approx. | 350 | kW |
| (TEWAC without SSS clutches) | Anti-icing | approx. | (25) | kW |
| | Operation | approx. | 190 | kW |
| For details refer to the relevant | Aftercooling | approx. | 110 | kW |
| consumer lists | Standstill | approx. | 60 | kW |
| **Motor Control Centre (MCC)** | | | | |
| Connection (input side) | terminal strips in incoming feeder cabinet | | | |
| Voltage required | 400 VAC (3Phase) | | | |
| Tolerance required | +5/-10% | | | |
| Mounting | electrical room with air condition +5...30°C with raise floor | | | |
| Single line diagram no. | See in Chapter 14 | | | |
| **Battery station 125 V DC / Battery station 24 V DC** | | | | |
| Mounting | battery room with air condition +5...30°C | | | |
| Single line diagram no. | See in Chapter 14 | | | |
| **UPS - system 230 V 1Ph** | | | | |
| Mounting | battery room with air condition +5...30°C | | | |
| Single line diagram no. | See in Chapter 14 | | | |

| System | **Instrumentation / Signals** |
|---|---|
| Connection | Terminal boxes/Terminal boards at components/skids/control cubicles |
| Diagram no. | Later |

| System | **Earthing** |
|---|---|
| Connection (to customers earthing system) | earth lugs at the base frame of the components |
| Diagram no. | to follow |





## 5. PERFORMANCE DATA

### Attachments

- Guarantee Data **(later)**
- LCP Annex VI – Gas Turbines **(later)**
- Expected Fuel Gas Pressure vs. Electrical Power Output **(later)**
- Performance Data **(later)**
- Consumer List FT8 TwinPac **(later)**
- Consumption List **(later)**
- FT8 TwinPac Start-up Profile (Normal Start) **(later)**
- FT8 TwinPac Start-up Profile (Black Start) **(later)**
- FT8 TwinPac Shut-down Profile Speeds
- FT8 TwinPac Emergency Shut-down Profile Speeds **(later)**
- Estimated Degradation of Power Output and Heat Rate at Continuous Load with Natural Gas Fuel after Compressor Wash **(later)**
- Estimated Degradation of Power Output and Heat Rate at Continuous Load with Fuel Oil No. 2 after Compressor Wash **(later)**
- Expected Shaft Power vs. Inlet Temperature **(later)**
- Heat Rate Correction Factor for Inlet Temperature **(later)**
- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Ambient Pressure **(later)**
- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Altitude **(later)**
- Relative Humidity Correction Factor for Power Output **(later)**
- Power Correction Factor for Inlet Temperature **(later)**





- Correction Factor for Power Output and Mass Flow (Inlet & Exhaust) vs. Altitude **(later)**
- Influence of Inlet Pressure Losses on Power, Heat Rate, Exhaust Mass Flow and Exhaust Gas Temperature relative to Base Load at ISO Conditions **(later)**
- Influence of Exhaust Pressure Losses on Power, Heat Rate, Exhaust Mass Flow and Exhaust Gas Temperature relative to Base Load at ISO Conditions **(later)**





## 6. OTHERS

### Attachments

- Specification Gaseous Fuels FT8 Gas Turbines **(later)**
- Specification Water for Injection into Combustion Chamber FT8 Gas Turbines **(later)**
- Specification Liquid Fuels FT8 Gas Turbines **(later)**
- Specification Lube Oil **(later)**
- Specification Hydraulic Oil **(later)**
- Turbo-K Gas Turbine Compressor Cleaner **(later)**
- Sub Vendor List **(later)**
- Sound Power Calculation **(later)**
- Technical Description of Gas Turbine and Ancillaries **(later)**
- Painting Specification **(later)**





## 7. THERMAL AND MECHANICAL ENGINEERING

### Attachments

- List of media **(later)**
- Data sheet for design of HVAC **(later)**
- Data sheet for design of drain systems **(later)**
- Data sheet for fire load **(later)**
- Industrialization JT8D-219 Air Engine FT8 Industrial Gas Turbine **(later)**
- FT8 Secondary Airflow and Lubrication Systems **(later)**
- Modular System **(later)**
- Gate Cycle Report - GT Report **(later)**
- Industrial Gas Turbine FT8
  Bill of Material FT8-30 Gas Turbine **(later)**
- System Engineering Gas Turbine FT8 **(later)**
- Instrument Gas Turbine Drawing No. 10000415327 **(later)**
- P&I Diagram Drawing No. 105369-00-01-B **(later)**
- Rohrleitungsliste Drawing No. 10000302523 **(later)**
- Vibration Monitor Checkout Procedures **(later)**
- Contoured Diaphragm Flexible Coupling Drawing No. 67R322-4888 **(later)**
- INSTALLATION AND MAINTENANCE MANUAL Power Transmission Couplings **(later)**





# 8. SCHEDULES, PROJECT ADMINISTRATION

## 8.1 Detailed schedule of the delivery

### Attachment

- BAR CHART / BID - PLANNING: 30070xx.30 HARDWOOD POWER PLANT 2 x FT8-36 Gas Turbine Sets) **(later)**





## 8.2 DOCUMENTATION

### Attachments

- Preliminary Drawing List GT-Generator Unit **(later)**





## 8.3 A description of the Supplier's project management system

### Attachment

- Organization Chart for project execution **(later)**





## 8.4 Site Activities and Arrangements

### Preliminary resource

Estimate 2-4, salaried employees and 8-21 workers per calendar month (Attachment Typical Installation of a Plant with 2x FT8-36 GT Sets) **(later)**

### Need of site facilities

| | |
|---|---|
| – office rooms | 2 pcs. 12 - 14 m² |
| – outdoor storage area | 1115 m² |
| – electric power (220 V) max. | 60 kW |

## 9. CIVIL ENGINEERING

### Attachments

- Layout Drawing **(later)**
- Foundation Loading Drawing **(later)**
- Lateral Natural Frequencies **(later)**
- Erection Documentation OLKTwin 1/ 2 **(later)**





## 10. INSTRUMENTATION AND CONTROL

### Attachments

- Control System Diagram FT8 PowerPac / TwinPac **(later)**
- FT8 TwinPac - Control System and Operation Modes **(later)**
- Speed PT Channel 3 Fault **(later)**
- Instrument List GT **(later)**
- Sequence Diagrams **(later)**
- Signal and Alarm List **(later)**
- GT UCP Layout **(later)**
- Specification Factory Acceptance Test UCP system **(later)**
- Overview Print of Visualisation System **(later)**
- GT Control Diagram **(later)**
- Functional Logic Description **(later)**





## 11. GENERATOR

### Attachments

- BRUSH TURBOGENERATORS – DAX 2-Pole Turbogenerator **(later)**
- Fingrid Step Load and Off Load Estimates **(later)**





## 12. EXCITATION EQUIPMENT

### Attachments

- Single line (Protection, Excitation and Synchronization System) **(later)**

# 13. GENERATOR PROTECTION, SYNCHRONISATION AND CONTROL

## Attachments

- GCP - Generator Control Panel **(later)**





## 14. ELECTRICAL POWER EQUIPMENT

### Attachments

- Overview Junction Boxes (GT) **(later)**
- Cable List Drawing No. 10000259260 **(later)**
- Motor Control Center ENERGON **(later)**
- LV Single Line Diagram **(later)**
- Uninterrupted Power Supply THYROTRONIC **(later)**
- Layout UPS **(later)**
- UPS Single Line Diagram **(later)**

## 15. DRAWINGS OF AUXILIARY PLANT COMPONENTS

### Attachments

- Liquid Fuel Skid **(later)**
- Gas Fuel Skid **(later)**
- Lube Oil Unit Gas Turbine, Drawing No. 10000173647 **(later)**
- Plate Heat Exchanger (GT) **(later)**
- Oil Demister, Drawing No. 10000176150 **(later)**
- Dehumidifier - Assembly ML-420 **(later)**
- Lube Oil Filling Device, Drawing No. 10000178754 **(later)**
- Layout Mobiles Wash Skid, Drawing No. 10000014925 **(later)**
- Cold Air Buffer (CAB) **(later)**
- 2-Stage, 2-Side Static Filterhouse **(later)**
- Exhaust Stack with Silencer **(later)**





## 16. ELECTRICAL SYSTEMS - OUTSIDE GT BASE SCOPE

- General
- Power to grid system **(later)**

  - Generator busbar system
  - Generator breakers
  - Main transformer
  - Transformer over voltage and neutral point equipment
  - Transformer protection system

- Auxiliary transformer **(Later)**
- Building electrification **(Later)**

## 17. CONTINUOUS EMISSION MONITORING SYSTEM

### INTRODUCTION

A complete system is offered for the continuous measurement of emissions of a GT Power station.
All necessary analysis equipment, auxiliaries services, piping, cabling, cabin modules, data acquisition system and services are included performing a turn-key by project.

All equipments offered are test approved by TÜV-Reinland and accepted by European & Spanish Authorities.

### TECHNICAL DESCRIPTION

#### 1. MAIN STARTING DATA

Stack expected emissions:

- Concentration SO2 < 500 mg/m3
- Concentration CO < 500 mg/m3
- Concentration NOx < 100 mg/m3
- Temperature: to be defined (< 500 °C)
- Flow: to be defined

Stack characteristic:

- Diameter: to be defined
- Thickness: to be defined
- Platform: to be defined

#### 2. MEASURING COMPONENTS

Following ranges are proposed:

| Components | Ranges |
|---|---|
| SO2 | 0 – 100 / 500 mg/m3 |
| NO | 0 – 25 / 0 - 100 mg/m3 |
| CO | 0 – 100 / 500 mg/m |
| CO | 0 - 10 Vol |
| $O_2$ | 0 - 21 Vol % |
| Dust | 0 – 200 mg/$Nm^3$ |
| Flow | (Calculated) 0 – 50.000 Nm3/h |

| | |
|---|---|
| Temperature | 0 – 600 °C |
| Absolute Pressure | 800 -1.200 mbar |

Note :
Other ranges are also possible.

**3. SCOPE OF SUPPLY**

3.1 Gas sampling and conditioning system. Including filtering and standard flanges.

3.2 Heated sample lines with heated tube PTFE. UV protection ∅ 45. Electrical connection 220 V Pt100. Output máx 90 VA/m. Máx. working temp. 20ºC. Estimated length= 15 m.

3.3 Emission analyzer with:
Modular system S710 configuration holder 19", with following modules:

Multor: for measurement of components CO2, CO, NO, OXOR for measurement of O2.
Module UNOR: for measurement of components SO2.

Sample conditioning with cooling device, filter, and pumps.

Outdoor cabinet full equiped aprox: 2100 x 800 x 600 with air conditioned.
Power supply: 400 / 230V, 50 Hz

3.4 Dust Monitoring system by the method of light transmission SICK model OMD41 including purge and fail safe schutters. Weather protection.

3.5 Flow, pressure, temperature from stack.

Weather station (humidity, pres. Abs. and ambient temperature.

3.6.Data acquisition system
With: I/o modules to collect all analog/digital signals: Module DAS8000 (for 8 analog /digital signals) and communication modules DA4000 Communication Modules Modbus
2 x PC complete with printer
Software per emission control acc.to the national rules. Based on:

- Base dates Access
- Visual Basic

Software data treatment with:

- Viewer data





- Summary of medium values, ½ values and daily values for each component.

3.7 Set span Gas and Regulators with:

- Gas set span gas bottles & regulation devices.
- Gas certifications.

3.8 Installation of all equipments considering that the CEMS container with be located at the bottom of the stack incl. cabling & supports. Max.length 20 m.

3.9 Drawing & manuals in English/French.

**NOTES:**

1) Electrical connection to be taken at stack bottom.
2) Any TÜV or similar institute test are not considered.
3) No cabling from the cabinet to the control room is considered.

| Pos. | Quant. | Description per each FT8 TwinPac | Qty |
|---|---|---|---|
| Pos. 1 | 1 | Gas sampling system | 2 |
| Pos. 2 | 1 | Heated sample lines (15 meters) | 2 |
| Pos. 3 | 1 | Analyzer modules MAIHAK S 710 in a outside cabinet for: (CO, CO2, NO, O2) | 2 |
| Pos. 3.2 | 1 | Analyzer module UNOR for SO2 | 2 |
| Pos. 4 | 1 | Dust Monitoring system SICK OMD41 | 2 |
| Pos. 5 | 1 | Flow, temp. and abs. pressure | 2 |
| Pos. 6 | 1 | Data acquisition system consisting in 2 PC with MODBUS standard connection (for both systems) | 1 |
| Pos. 7 | 1 | Special span gases set for control of both systems | 1 |
| Pos. 8 | 1 | Installation (for both systems) | 1 |

**Attachments**





- Process Diagramm **(later)**
- Gas Analysis – S 700, Modular Gas Analyzer System **(later)**
- S 700, Modular Gas Analyzer System, Data Sheet **(later)**
- OMD 41 – Dust Concentration Monitor **(later)**
- FW 100 – Dust Concentration Measuring Device **(later)**
- RM 210 – Dust Concentration **(later)**





## 18. CO CATALYST

### Attachments

- Description **(later)**
- Performance Data **(later)**

## 19. BLACK-START DIESEL GENERATOR UNIT

| | |
|---|---|
| GENSET-PERFORMANCE | 515 kVA / 412 kW Stand-by Power |
| Voltage: | 460 / 240 V |
| Frequency: | 60 Hz |
| Speed: | 1.800 1/min |
| Cos. phi: | 0,8 |

Details see attached. **(later)**





# 20. OPTIONS - OUTSIDE GT BASE SCOPE

## 20.1 HI-FOG System

### Attachment

- HiFog Fire Fighting MAU, Drawing No. 10000175886 **(later)**
- HI-FOG water mist fire protection
  Protecting Machinery & Power Generation Equipment **(later)**





## 20.2 Closed Cooling System

### Attachments

- Calculation **(later)**
- P&I Diagram **(later)**
- Drawing Cooling Plant / Units **(later)**





## 20.3 Air Cooled Solutions

### Attachment

- DAC Generators **(later)**
- Oil/air heat exchangers for industrial use **(later)**
- Specification Air-Oil-Cooler **(later)**

## 20.4 Anti-Icing System with Exhaust and Sound Protection System

### Attachment

- Drawing **(later)**

In the drawing is integrated the exhaust heating system for anti-icing with many references in all our compressor station installations in Germany for E.on Ruhrgas and WINGAS.

Also in this drawing is shown the modification of the exhaust stack according to lower sound restriction in connection with neighbours in an urban area.

In reference to the German TA Lärm the specification for this kind of area have different mdifications of the night level for this area and for the operation time per day.





## 20.5 Air Pressure Skid

### Attachment

- Layout Air Pressure Skid **(later)**
- KAESER Compressor SK 19/26 **(later)**
- KAESER Air Receivers **(later)**





## 21. QUALITY ASSURANCE AND CONTROL

### Attachments

- TG-QUALITY ASSURANCE **(later)**
- Certificates **(later)**
- Inspection and test plan **(later)**
- PWPS FT8-1 and FT8-3 Production Acceptance Test Overview **(later)**
- PWPS Factory Acceptance Tests **(later)**
- Field-Acceptance Test Procedure , Thermodynamic Performance Test of a FT8-30/36 TwinPac (Generator Drive) on Site **(later)**





## 22. TRAINING

### Attachments

- Training at Customer site **(later)**
- Training at Contractor site **(later)**
- Time Schedule of Traing **(later)**
- Course description for Operator Team **(later)**
- Course description for Mechanical Team **(later)**
- Course description for Electrical Team **(later)**
- Course description for Control & Instrumentation Team **(later)**





## 23. INFORMATION ON GAS TURBINE SERVICE

### Attachments

- FT8 General Service Concept **(later)**
- Budgetary Offer **(later)**
- Special Tools FT8 **(later)**
- GT Spare Parts Proposal **(later)**
- Audit Spare Parts Proposal **(later)**
- Generator Spare Parts (BEM) **(later)**





## 24. QUALIFICATION OF TENDERERS

**(later)**





## 25. ANNUAL REPORTS

MAN TURBO AG **(later)**

and

MAN AG **(later)**

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **Public Service Electric & Gas Co.**<br>Burlington, New Jersey, USA | 4 (2 TP)<br>4 (2 TP) | Combined Cycle<br>Combined Cycle | Mar 92<br>June 93<br>(Status: 31.12.04) | total<br>116.805 |
| **Futian Power Company**<br>Shenzhen, PR China | 1 (PP) | Combined Cycle | Mar 92<br>(Status: 31.12.04) | 54.641 |
| **Newfoundland and Labrador Hydro**<br>Happy Valley, Labrador, Canada | 1 (PP) | Power Generation (Peaking plus Synchronous Condensing) | March 92<br>(Status: 31.12.04) | total<br>1.163<br>(64.372) |
| **Ebara Corporation**<br>Sodegaura, Japan | 1 (PP) | Power Generation (Peaking) | July 92<br>(Status: 31.12.04) | 10.626 |
| **MAN TURBO AG**<br>Oberhausen, Germany | 1 (MD) | Test Stand | July 92 | 500 |
| **United Technologie Corporation**<br>**P & W Manufacturing Division**<br>East Hartford, Connecticut, USA | 1 (PP) | Cogeneration | Jan. 93<br>(Status: 31.12.04) | 71.776 |
| **Mitsubishi Heavy Industries**<br>Takasago, Hyogo<br>Car & Passenger Ferry, Japan | 2 GG8 f. MFT8 (MD) | Marine Propulsion | 1994<br>(Status: 31.12.02) | total<br>13.000 |
| **Hainan Electric Power Company**<br>Sanya, Hainan Province, PR China | 2 (TP)<br>2 (TP) | Power Generation (Base Load) | Apr. 94<br>June 95<br>(Status: 31.12.04) | total<br>203.171 |
| **Jamaica Public Service Company**<br>Montego Bay, Jamaica | 2 (PP) | Power Generation (Base Load) | Dec. 94<br>(Status: 31.12.04) | total<br>24.476 |
| **Industriekraftwerk Baienfurt**<br>Baienfurt, Germany | 1 (PP) | Combined Cycle | Feb. 95 | 97.084 |
| **Massachusetts Water Resources Authority**<br>(formerly Boston Edison Company)<br>Deer Island, Boston,<br>Massachusetts, USA | 2 (PP) | Power Generation (Emergency) | June 95<br>(Status: 31.12.04) | total<br>3.609 |
| **Rhodia Energy**<br>Melle, France | 1 (PP) | Cogeneration | Sep. 95 | 43.694 |
| **E.ON Ruhrgas Aktiengesellschaft**<br>Station Werne 7, Germany | 1 (MD) | Pipeline | Oct. 95 | 37.905 |
| **Energieversorgung Oberhausen AG**<br>Oberhausen, Germany | 1 (PP) | Cogeneration | Dec. 95 | 71.938 |
| **Wuxi Suyuan Gas Turbine Electric Company**<br>Wuxi County, PR China | 2 (TP) | Combined Cycle | July 96<br>(Status: 31.12.04) | total<br>19.700 |
| **ESYS-MONTENAY**<br>Clermont-Ferrand, France | 1 (PP) | Cogeneration | Oct. 96 | 38.952 |

PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **Chloralp** | 3 (PP) | Cogeneration | Sep. 96 | 50.045 |
| Pont de Claix, France | | | Sep. 96 | 51.932 |
| | | | Oct. 96 | 52.516 |
| **Cogeneration Management Steiermark** | 1 (PP) | Cogeneration- | Sep. 96 | 69.189 |
| Graz, Austria | | | | |
| **Solvay Deutschland** | 2 (TP) | Cogeneration | Sep. 96 | 87.765 |
| Rheinberg, Germany | | | | 86.437 |
| **TransCanada Pipelines** | | | | |
| Kapuskasing, Canada | 1 (PP) | Combined Cycle | Dec. 96 | 59.072 |
| North Bay, Canada | 1 (PP) | Combined Cycle | Dec. 96 | 59.022 |
| | | | (Status: 31.12.04) | |
| **Asahi Chemical Industry Co. Ltd.** | 1 GG8 f. MFT8 (PP) | Combined Cycle | Apr. 97 | 63.000 |
| Kanagawa, Japan | | | (Status: 31.12.04) | |
| **Chengdu AES-Kaihua** | 2 (TP) | Power Generation | June 97 | total |
| **Gas Turbine Power Co. Ltd.** | | (Base Load) | (Status: 31.12.04) | 42.787 |
| Chengdu, PR China | | | | |
| **I.C. Industrias, S.A.** | 2 (TP) | Power Generation | Sep. 97 | total |
| La Dorada, Colombia | | (Base Load) | (Status: 31.12.04) | 19.407 |
| **Communauté Electrique du Benin** | | | | |
| Lorne, Togo | 1 (PP) | Power Generation | June 98 | 15.841 |
| Contonou, Benin | 1 (PP) | (Base Load) | July 98 | 12.241 |
| | | | (Status: 31.12.03) | |
| **Endesa** | | | | |
| Charrua, Chile | 2 (PP) | Power Generation | Feb. 99 | total |
| | | (Base Load) | (Status: 31.12.02) | 7.053 |
| Valdivia, Chile | 2 (TP) | Power Generation | Mar 99 | total |
| | 2 (PP) | (Base Load) | (Status: 31.12.02) | 8.132 |
| **BASF AG für WINGAS GmbH** | | | | |
| Rückersdorf Station, Germany | 1 (MD) | Pipeline | June 99 | 19.632 |
| Mallnow Station, Germany | 2 (MD) | Pipeline | Oct. 99 | 34.804 |
| | | | Nov. 99 | 33.076 |
| **Tomen Power Samukawa** | 2 (TP) | Combined Cycle | June 99 | total |
| Samukawa, Kanagawa, Japan | | | (Status: 31.12.04) | 32.423 |
| **Ebara Corporation** | 2 (TP) | Combined Cycle | June 99 | total |
| Fujisawa, Kanagawa, Japan | | | (Status: 31.12.04) | 32.715 |
| **E.ON Ruhrgas Aktiengesellschaft** | 1 (MD) | Pipeline | June 99 | 24.162 |
| Station Werne 8, Germany | | | | |
| **Adisseo France S.A.S.** | 1 (PP) | Cogeneration | Sep. 99 | 30.109 |
| Commentry, France | | | | |
| **CURCHAL** | 1 (PP) | Cogeneration | Dec. 99 | 26.408 |
| Chalon s/Saône, France | | | | |
| **Tokyo Metropolitan Government** | 2 GG8 f. MFT8 (MD) | Pump Drive | Jan. 00 | total |
| Kanto Chisei, Japan | | | | 278 |

PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **Omaha Public Power District** | 4 (2 TP) | Power Generation | May 00 | total |
| Omaha, Nebraska, USA | | (Peaking) | (Status: 31.12.04) | 10.994 |
| **Buckeye Power** | 8 (4 TP) | Power Generation | May 00 | total |
| Greenville, Ohio, USA | | (Peaking) | (Status: 31.12.04) | 17.157 |
| **BASF AG für WINGAS GmbH** | | | | |
| Mallnow Station, Germany | 1 (MD) | Pipeline | Jan. 01 | 36.760 |
| Rückersdorf Station, Germany | 1 (MD) | Pipeline | Apr. 01 | 24.998 |
| **Boremer** | 1 (PP) | Cogeneration | May 01 | 51.130 |
| San Martin de la Vega, Spain | | | | |
| **Tokyo Metropolitan Government** | 1 (PP) | Power Generation | Jan. 01 | 868 |
| Higashi Kojiya Pumpstation, Tokio Japan | | (Emergency) | (Status: 31.12.04) | |
| **DPL Energy, Inc.** | 8 (4 TP) | Power Generation | May 01 | total |
| Montpelier, Indiana, USA | | (Peaking) | (Status: 31.12.04) | 9.973 |
| **Tenaska** | 10 (5 TP) | Power Generation | July 01 | total |
| Wolf Hills, Bristol, Virginia, USA | | (Peaking) | (Status. 31.12.04) | 6.533 |
| **Tenaska** | 12 (6 TP) | Power Generation | July 01 | total |
| University Park, Chicago, Illinois, USA | | (Peaking) | (Status: 31.12.04) | 4.465 |
| **Constellation Power** | 10 (5 TP) | Power Generation | July 01 | total |
| Handsome Lake, Rackland Township, Pennsylvania, USA | | (Peaking) | (Status: 31.12.04) | 6.224 |
| **Tenaska** | 12 (6 TP) | Power Generation | July 01 | total |
| Big Sandy, Neal, West Virginia, USA | | (Peaking) | (Status: 31.12.04) | 5.023 |
| **Puget Sound** | 4 (2 TP) | Power Generation | July 01 | total |
| Fredonia, Washington, USA | | (Peaking) | (Status: 31.12.04) | 8.725 |
| **Virgin Islands Water & Power Auth.** | 1 (PP) | Power Generation | Sep. 01 | 5.220 |
| St. Thomas, US Virgin Islands | | (Base Load) | (Status: 31.12.04) | |
| **CalPeak** | | | | |
| Escondido, California, USA | 2 (TP) | Power Generation | Sep. 01 | total |
| | | (Peaking) | (Status: 31.12.04) | 2.827 |
| Border, California, USA | 2 (TP) | Power Generation | Sep. 01 | total |
| | | (Peaking) | (Status: 31.12.04) | 2.767 |
| Panoche, California, USA | 2 (TP) | Power Generation | Nov. 01 | total |
| | | (Peaking) | (Status: 31.12.04) | 1.764 |
| **Benton PUD** | 1 (PP) | Power Generation | Oct. 01 | |
| Benton Country, Washington, USA | | (Peaking) | (Status: 31.12.04) | 1.025 |
| **Jamaica Public Service Company** | 1 (PP) | Power Generation | Jan. 02 | 6.599 |
| Montego Bay, Jamaica | | (Peaking) | (Status: 31.12.04) | |
| **City Utilities of Springfield** | 4 (2 TP) | Power Generation | Feb. 02 | total |
| Springfield, Missouri, USA | | (Peaking) | (Status: 31.12.02) | 2.000 |
| **PacifiCorp** | 4 (2 TP) | Power Generation | Apr. 02 | total |
| Klamath Falls, Oregon, USA | | (Peaking) | (Status: 31.12.04) | 1.725 |

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SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **Ameren UE** | | | | |
| Peno Creek, Bowling Green, Missouri, USA | 8 (4 TP) | Power Generation (Peaking) | Apr. 02 (Status: 31.12.03) | total 5.814 |
| Venice, Meremac, Illinois, USA | 2 (TP) | Power Generation (Peaking) | May 02 (Status: 31.12.03) | total 1.168 |
| **Rochester Public Utility** Rochester, Minnesota, USA | 2 (TP) | Power Generation (Peaking) | May 02 (Status: 31.12.04 | total 1.564 |
| **CalPeak** | | | | |
| Vaca Dixon, California, USA | 2 (TP) | Power Generation (Peaking) | June 02 (Status: 31.12.04) | total 1.379 |
| El Cajon, California, USA | 2 (TP) | Power Generation (Peaking) | June 02 (Status: 31.12.02) | total 2.636 |
| **Petrobras Termoceara** Fortaleza, Brazil | 8 (4 TP) | Power Generation (Peaking) | June 02 (Status: 31.12.02) | total 21.398 |
| **FPL Energy** Bayswater, New York, USA | 2 (TP) | Power Generation (Peaking) | June 02 (Status: 31.12.04) | total 8.491 |
| **Ebara Corporation** Sodegaura, Japan | 3 (PP) | Combined Cycle | Dec. 02 (Status: 31.12.04) | total 22.823 |
| **Michigan Public Power** Kalkaska, Michigan, USA | 2 (TP) | Power Generation (Peaking) | Dec. 02 (Status: 31.12.04) | total 993 |
| **Empire Electric** Sarcoxie, Missouri, USA | 4 (2 TP) | Power Generation (Peaking) | Feb. 03 (Status: 31.12.04) | total 4.624 |
| **Endesa** Mahon, Menorca, Spain | 2 (TP) | Power Generation (Peaking) | June 03 (Status: 31.12.04) | total 3.043 |
| **Endesa** Arona, Tenerife, Spain | 2 (PP) | Power Generation (Peaking) | June 03 (Status: 31.12.04) | total 10.367 |
| **FPL Energy** Jamaica Bay, New York, USA | 2 (SP50) | Power Generation (Peaking) | June 03 (Status: 31.12.04) | total 2.030 |
| **Global Commons Greenport LLC** Greenport, New York, USA | 2 (SP50) | Power Generation (Peaking) | July 03 (Status: 31.12.04) | total 3.182 |
| **Electricity Supply Board** | | | | |
| Asahi, County Mayo, Ireland | 2 (SP50) | Power Generation (Peaking) | Dec. 03 (Status: 31.12.04) | total 630 |
| Aghada, County Cork, Ireland | 2 (SP50) | Power Generation (Peaking) | Dec. 03 (Status: 31.12.04) | total 561 |
| **Ministry of Oil** Al-Bashrah, Iraq | 2 (TP) | Power Generation (Base Load) | Mar 04 | |
| **Ministry of Electricity** Al-Hilla, Iraq | 1 (PP) | Power Generation (Base Load) | Mar 04 | 6.400 |
| **Contact Energy** Whirinaki, New Zealand | 6 (SP50) | Power Generation (Peaking) | Apr. 04 (Status: 31.12.04) | total 1.148 |
| **Wisconsin Public Power** Kaukaua, Wisconsin, USA | 2 (TP) | Power Generation (Peaking) | May 04 (Status: 31.12.04) | total 958 |

PP = PowerPac, TP = TwinPac,
SP = SwiftPac, MP = MobilePac,
MD = Mechanical Drive

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **Endesa** | 2 (SP50) | Power Generation | Sep. 04 | total |
| Guio de Isora, Tenerife, Spain | | (Peaking) | (Status: 31.12.04) | 282 |
| **Electricity Supply Board** | 4 (SP50) | Power Generation | Sep. 04 | total |
| Rhode, County Offaly, Ireland | | (Peaking) | (Status: 31.12.04) | 483 |
| **Endesa** | 1 (MP) | Power Generation | Nov. 04 | |
| Las Palmas, Spain | | (Peaking) | | |
| **Tokyo Metropolitan Government** | 2 GG8 f. | Pump Drive | Jan. 05 | total |
| Kanto Chisei, Japan | MFT8 (MD) | | (Status: 31.12.04) | 400 |
| **Kraftnät Åland AB** | 1 (PP) | Power Generation | March 05 | 155 |
| Tingsbacka, Åland, Finland | | (Emergency) | | |
| **BASF AG für WINGAS GmbH** | 1 (MD) | Pipeline | May 05 | 15.318 |
| Reckrod Station, Germany | | | | |
| **BASF AG für WINGAS GmbH** | | | | |
| Rückersdorf Station, Germany | 1 (MD) | Pipeline | Feb. 06 | 6.791 |
| Eischleben Station, Germany | 1 (MD) | Pipeline | May 06 | 1.496 |
| **Bell Bay Power** | 6 (3TP) | Power Generation | Mar 06 | |
| Tasmania, Australia | | (Peaking) | | |
| **JSC Energy Invest** | 4 (SP50) | Power Generation | Apr. 06 | |
| Gardabani Power Station | | (Intermediate) | | |
| Republic of Georgia | | | | |
| **Amber Investment** | 2 (SP50) | Combined Cycle | June 06 | |
| Changxing County, Zhejiang, PR China | | | | |
| **Beijing Blue Sky Gas-fired Cogeneration Co.** | 4 (2 TP) | Cogeneration | June 06 | |
| Beijing, PR China | | | | |
| **EADC/EAS** | 4 (SP50) | Power Generation | Nov. 06 | |
| Charrua, Chile | | (Base Load) | | |
| **Seminole Electric Cooperative** | 10 (SP50) | Power Generation | Dec. 06 | |
| Central Florida, USA | | (Peaking) | | |
| **RAO UES** | 10 (MP) | Power Generation | Jan. 07 | |
| Moscow, Russia | | (Peaking) | | |
| **EDF #1** | 1 (MP) | Power Generation | Feb. 07 | |
| Various Islands | | (Peaking) | | |
| **Guongzhou University** | 4 (SP50) | Combined Cycle | June 07 | |
| Guongzhou, PR China | | | | |
| **North Carolina Electric Memership Corp.** | | | | |
| Wake County, North Carolina | 12 (SP50) | Power Generation | June 07 | |
| Person County, North Carolina | 10 (SP50) | (Peaking) | Dec. 07 | |
| **Fingrid Oyj** | 4 (2 TP) | Power Generation | June 07 | |
| Olkiluoto, Finland | | (Emergency) | | |
| **EDF #2** | 1 (MP) | Power Generation | Oct. 07 | |
| Various Islands | | (Peaking) | | |

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MD = Mechanical Drive

**Reference List**
**FT8 Industrial Gas Turbine**
Status: 30. September 2007

| Customer / site location | No. of units | Application | Commis-sioning | Running hours |
|---|---|---|---|---|
| **ZAO UK "DKM-ENGINEERING"**<br>Moscow, Russia | 2 (SP25) | Combined Cycle (Cogeneration) | Dec. 07 | |
| **Campanario Generacion II**<br>Charrua, Chile | 2 (SP50) | Power Generation (Base Load) | Dec. 07 | |
| **STATTNETT SF**<br>Tjeldbergodden, Norway | 7 (MP) | Power Generation (Emergency) | Dec. 07 | |
| **STATTNETT SF**<br>Nyhamna, Norway | 6 (SP50) | Power Generation (Intermediate) | Dec. 07 | |
| **Nevada Power Company**<br>Las Vegas, Nevada, USA | 24 (SP50) | Power Generation (Peaking) | Apr. 08 | |
| **Endesa**<br>Ibiza, Spain | 1 (PP) | Power Generation (Peaking) | May 08 | |
| Ibiza, Spain | 1 (SP25) | Power Generation (Peaking) | Dec. 08 | |
| **Endesa**<br>Mahón, Menorca, Spain | 2 (SP50) | Power Generation (Peaking) | June 08 | |
| **Puerto Rico Electric Power Authority**<br>Mayaguez, Puerto Rico | 8 (SP50) | Power Generation (Intermediate) | June 08 | |
| **Generacion Mediterranea S.A.**<br>Central Modesto Maranzana<br>Rio Cuarto, Argentina | 4 (SP50) | Power Generation (Base Load) | July 08 | |
| **MEGAL**<br>Waidhaus, Germany | 1 (MD) | Pipeline | Nov. 08 | |
| **Endesa**<br>Mahón, Menorca, Spain | 2 (SP50) | Power Generation (Peaking) | Dec. 08 | |
| **Tokyo Metropolitan Government**<br>Higashi Kojiya Pump Station Unit 2<br>Tokyo, Japan | 1 (PP) | Power Generation (Emergency) | Dec. 09 | |
| **Total no. of engines in operation and running hours** | **232** | | | |
| **Total no. of engines sold** | **356** | | | **2.057.997** |

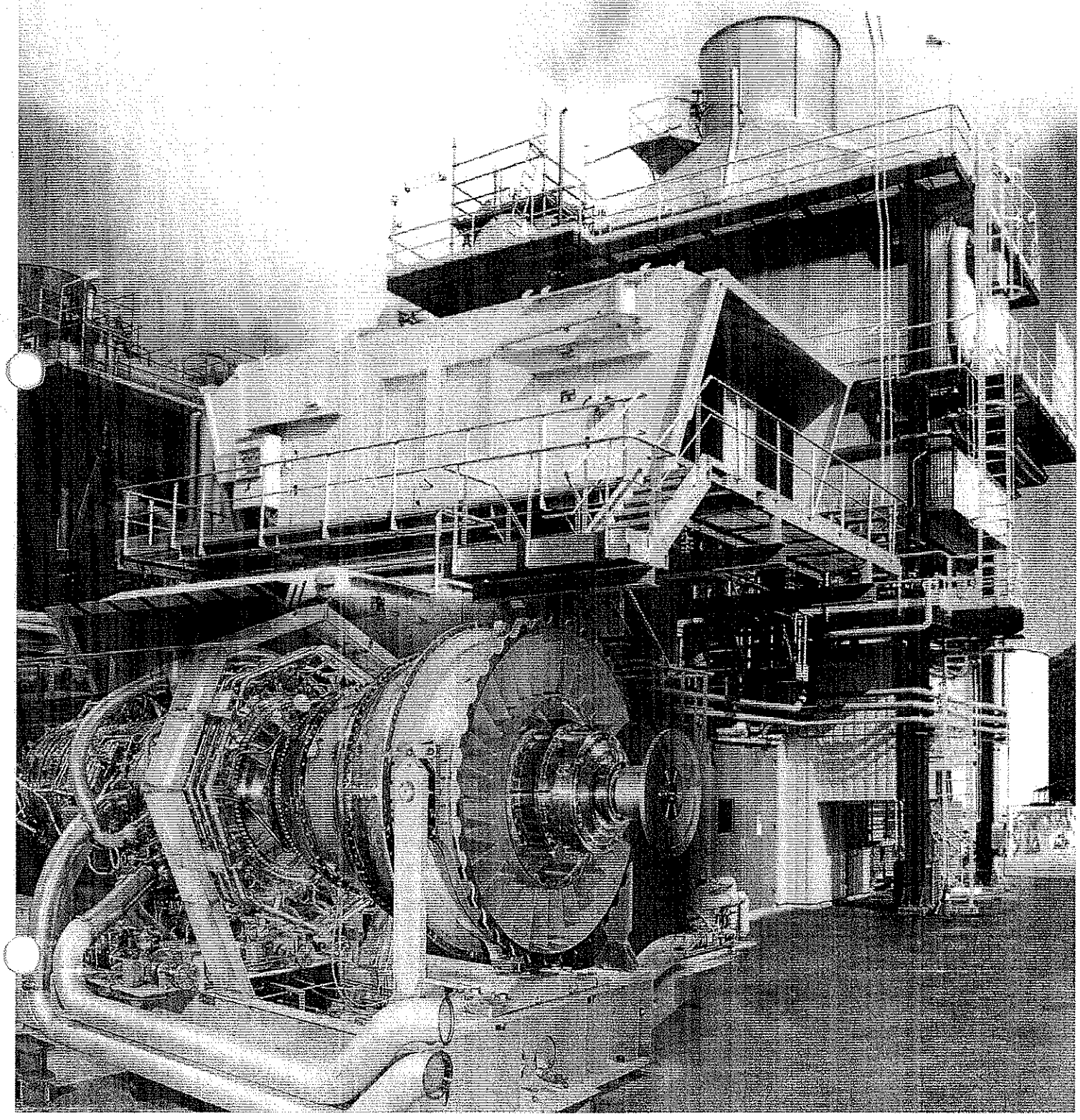
PP = PowerPac, TP = TwinPac,
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MD = Mechanical Drive

# FT8 Power Key to Plant Upgrade

GHH BORSIG

MAN TURBO

Welcome to the new Company



# FT8 Power Key to Plant Upgrade

## Revamping one of the first cogeneration plants in Europe

by Roberto Chellini, Diesel & Gas Turbine Worldwide
January/February 1999

The chemical works of the French company Rhodia (formerly Rhône-Poulenc Chemie) in Pont-de-Claix, is one of the largest industrial plants of the Grenoble region in southern France. With the acquisition of a capital share from LaRoche Industries Inc., all of Rhône-Poulenc Chimie's activities related to chlorine production were transferred to a joint venture (50 % LaRoche, 50 % Rhodia) named Chloralp.

Back in 1969, a large size cogeneration system was started at Pont-de-Claix to generate on-site electric power and process steam. The plant was originally based on eight Frame 5LA gas turbines rated 15 MW each, of which the first two units were delivered by Nuovo Pignone and the remaining by Alstom. In 1972 two similar units type Frame 5N rated 25 MW from Alstom were added. All 10 units are fitted with double pressure heat recovery steam generators from Babcock Atlantique. The HRSGs are placed directly on the turbine exhaust duct to produce superheated process steam at 30 bar and 270 °C, and a small amount of steam at 8 bar and 190 °C was also made available for flashing purposes.

Despite the relatively low efficiency of the industrial gas turbines available in the 1960s (22-24 %), the total fuel utilization rate of the cogeneration plant was quite high at approximately 70 %. The turbines were originally operated on liquid fuel and then shifted to natural gas after connection of the site to a main pipeline, leaving the liquid fuel as a backup in case of interruption of the gas supply. Furthermore, steam injection boosted the power of the first generation Frame 5s to 19 MW.

Normally the gas supply pressure to the plant is higher than required by the turbine fuel systems. However, should the pipeline pressure drop below the pressure needed by the gas turbines, single-stage Ariel compressors will take care of the necessary recompression.

In June 1996, three of the first heavy-duty industrial gas turbines were replaced by aeroderivative FT8 gas turbines ordered one year earlier from GHH BORSIG. The selection was made after an investigation of several parameters, two of which were of fundamental importance. The key element is the fact that the FT8 has a very similar mass flow compared to the Frame 5LA, so that the existing boilers could be used again after refurbishing and, secondly, the old foundation block could easily host the FT8 without major modifications.

After completion of the revamping program, operated by a 60 % ChlorAlp and 40 % Rhône-Poulenc joint company named CEVCO, the cogeneration plant has a capacity of 205 MW electric power and 700 t/h of process steam production.

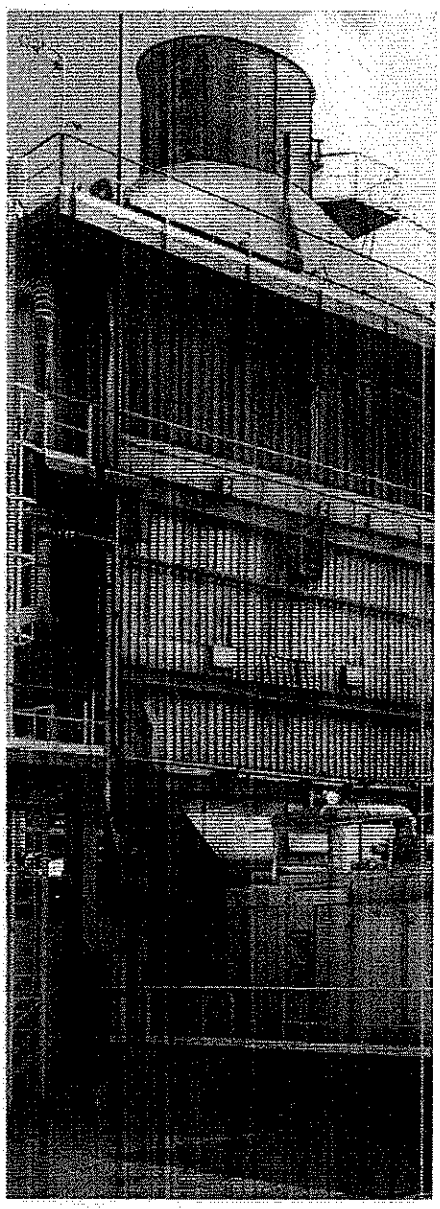
Today, the whole cogeneration system is managed in the following mode:

- The three FT8 units run at baseload; all electricity is sold to EDF (Eléctricité de France) according to the new DIGEC tariff commitment agreed with EDF and the steam is fed into the plant steam grid.
- The additional steam demand of the site is covered by starting up one or more Frame 5 units on request. The electricity generated in this way is absorbed at the chemical site. In case of further demand in electricity, this is bought from the EDF grid.

CEVCO has concluded a 12-year agreement with EDF to sell all the electric power produced by the FT8 gas turbines to the French utility in order to take advantage of the government incentives for new high-efficiency cogeneration plants. In France, these incentives are granted for plants with a total fuel utilization rate over 65 %, and the new section of the CEVCO plant is in the range of 88 %.

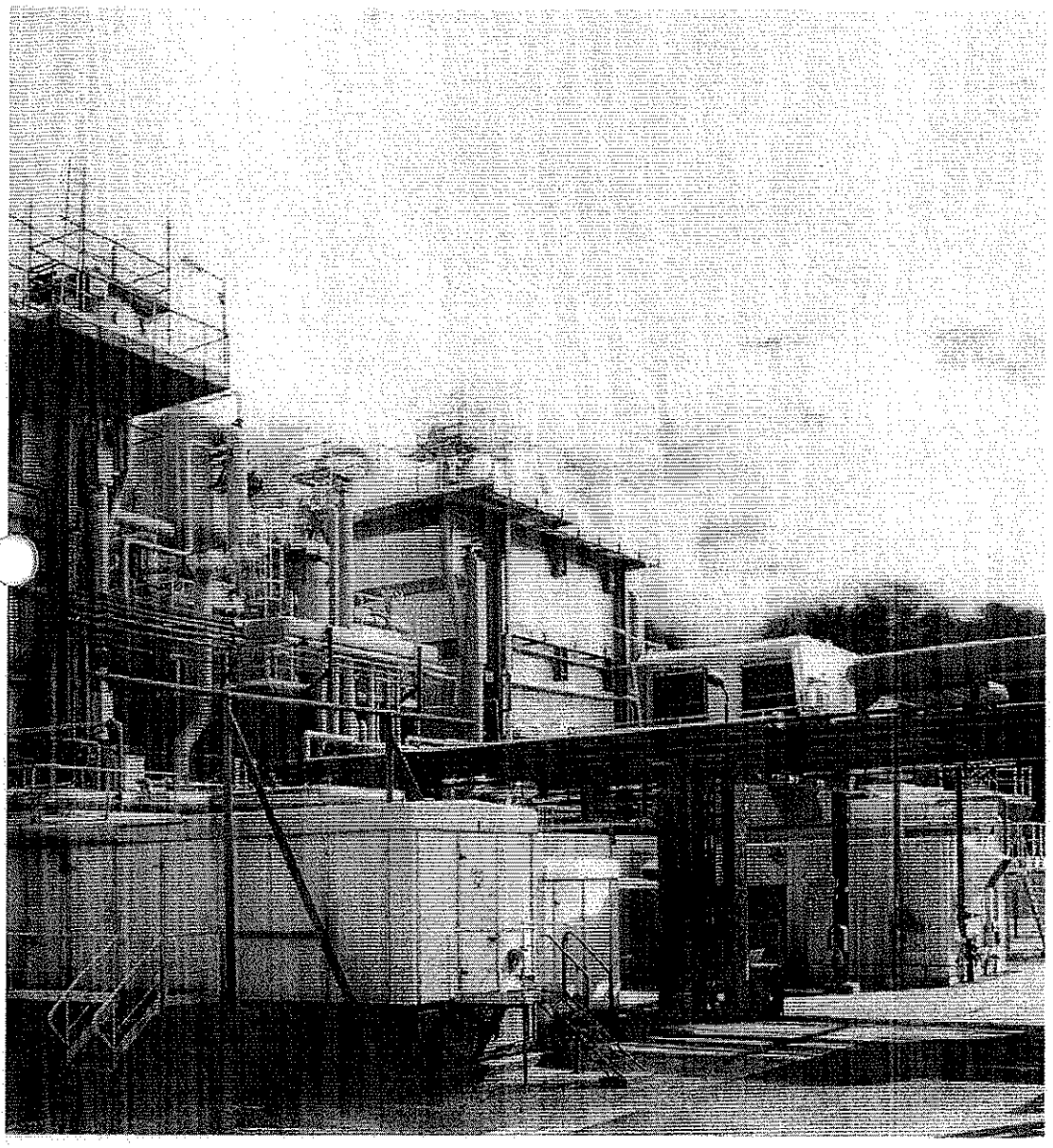
The whole cogeneration site is managed from the central control room where new monitors of Foxboro DCS have replaced the old synoptic panels of the scrapped machines. The new units are controlled via local control panels, which consist of a Woodward NetCon 5000 engine controller, a Siemens S5-115U PLC system with COROS visualization software. The COROS screens are remodeled on the CRT of the main control room so that the operator can run the machines from either position. Each gas turbine can be operated independently. The only common auxiliary for each group of two units is the water demineralization plant serving two boilers, while all the rest is separated.

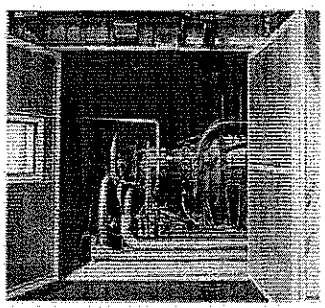
GHH BORSIG has installed the FT8 gas turbines on the existing foundations, with all equipment covered by waterproof and sound-attenuating enclosures that have been provided with a $CO_2$ fire protection system, as well as a forced ventilation system to take the heat radiation from the turbine outer casing. The turbine intake air system with filters and anti-icing device was delivered by Delbag and is installed upstream of the gas generator compartment. The



*The cogeneration plant at Pont-de-Claix, with a view of an existing Frame 5 gas turbine in the foreground and the new FT8 installation in the background.*

*A closer view of the complete FT8 gas turbine generator package and the refurbished HRSG.*





*The FT8 gas generator, with a 25 MW output.*

HRSG was left in its vertical position above the turbine exhaust. The natural circulation type HRSGs operate without bypass so that the turbines always have to be operated in the cogeneration mode.

New water-cooled 11 kV, 50 Hz, 35 MVA generators from Alstom complete with lube oil and cooling systems replaced the previous generators at the drive end of the gas turbine.

Next to one side of the turbine enclosure a separate container houses the auxiliaries like the synthetic lube oil system and the electric motor for driving the hydraulic pump that actuates the gas turbine starter. Also housed there is a supplementary demineralization system that further purifies the water treated by the boiler feed system before it is injected in the turbine combustor for lowering $NO_x$ emissions and increasing the power output.

CEVCO has the interest of selling as much power as available to EDF, so the FT8 turbines run constantly at full load. The three FT8 units were put into operation in November 1996. After a transition period during which the old EDF tariff contract was in force, the three FT8 cogeneration units have operated continuously since November 1997 according to the new DIGEC tariff. This is the first plant in France where FT8 turbines are kept at full load the year around.

In order to achieve the highest possible figures in terms of reliability and availability, CEVCO has awarded GHH BORSIG a full service maintenance contract which also implements the use of a floating gas generator or power turbine. In case of maintenance work required, GHH BORSIG's field personnel can replace a gas generator within 72 hours and a power turbine within 96 hours (intervention on the power turbine calls for realignment of the gas generator).

GHH BORSIG's After Sales division relies on native French or French-speaking field engineers to care for and support the five units now in operation in France, including three at Pont-de-Claix, one at Melle and one at Clermont-Ferrand.

Recently Rhône-Poulenc Animal Nutrition has ordered one more FT8 Power Pac, which adds up to a fleet of six FT8s in France so far.

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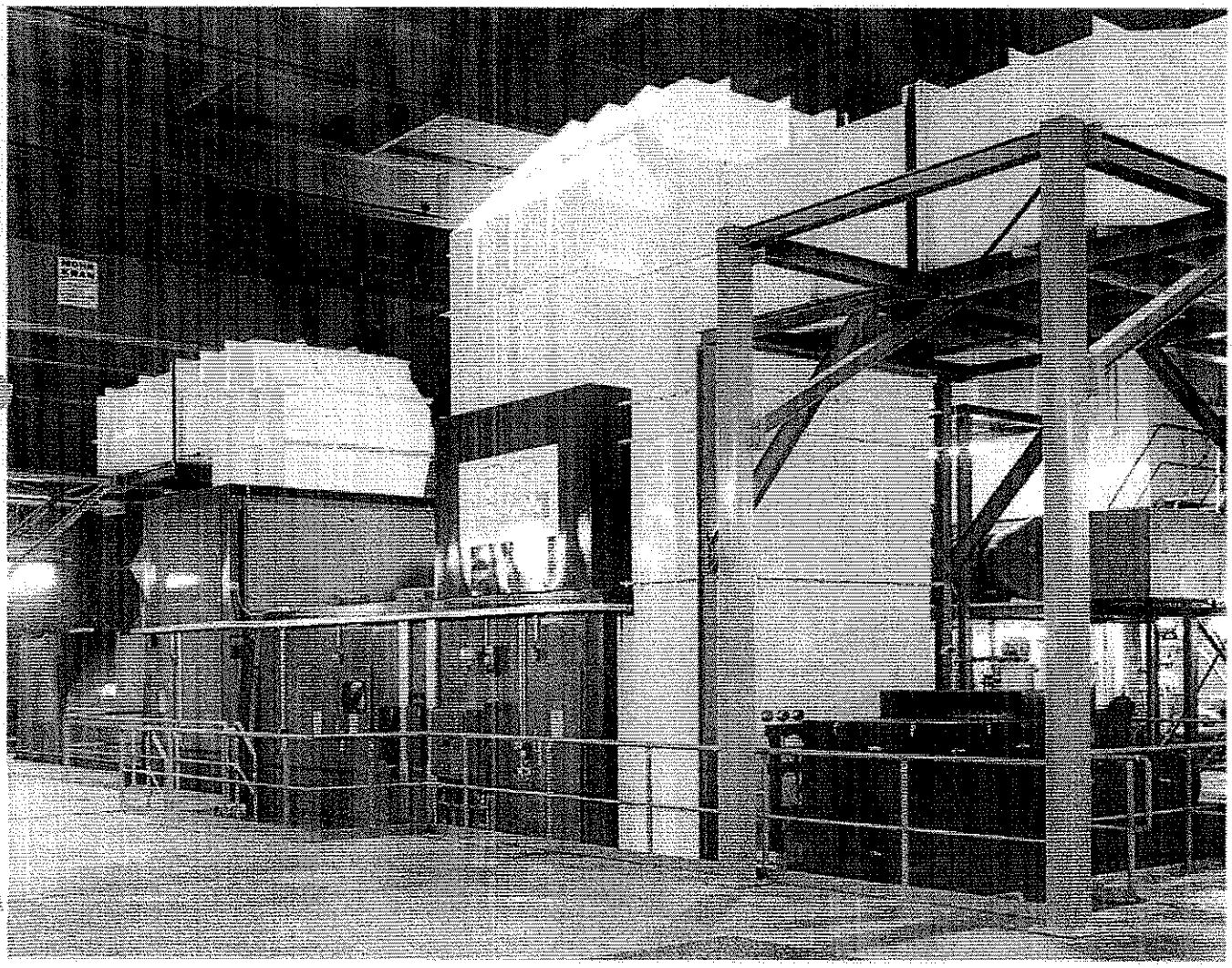
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# Integration of 25 MW gas turbine into existing power station

GHH BORSIG

MAN TURBO

Welcome to the new Company



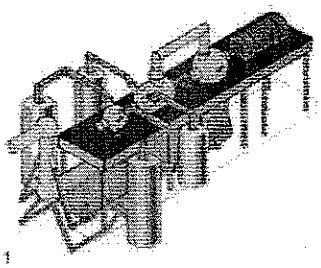
The combined heat and power station (CHP) supplied to the Oberhausen Public Utilities (EVO) by GHH BORSIG (formerly: MAN GHH) in 1974 has been revamped to produce an ultra-modern, fully automated gas turbine power station producing 25 MW of electric power. This was achieved by replacing the existing 50 MW helium turbine with a 25 MW gas turbine of type FT8. The old helium turbine had been developed and built by GHH in the course of development of the Federal Republic of Germany's fourth atomic programme. Components from the old installation have been largely integrated into the new plant design.

## Basic concept

The Oberhausen Public Utilities (EVO) power station has been modified from a 50 MW helium gas turbine installation to provide an ultra-modern, automated gas turbine power station, which supplies the town of Oberhausen with heat as well as power.

The order to supply the 25 MW gas turbine unit including waste heat recovery facility was awarded in January 1995 to a consortium made up of Deutsche Babcock Anlagen GmbH and GHH BORSIG Turbomaschinen GmbH (then MAN GHH). The order comprised the complete delivery of plant components, including revamping of existing components and building structures.

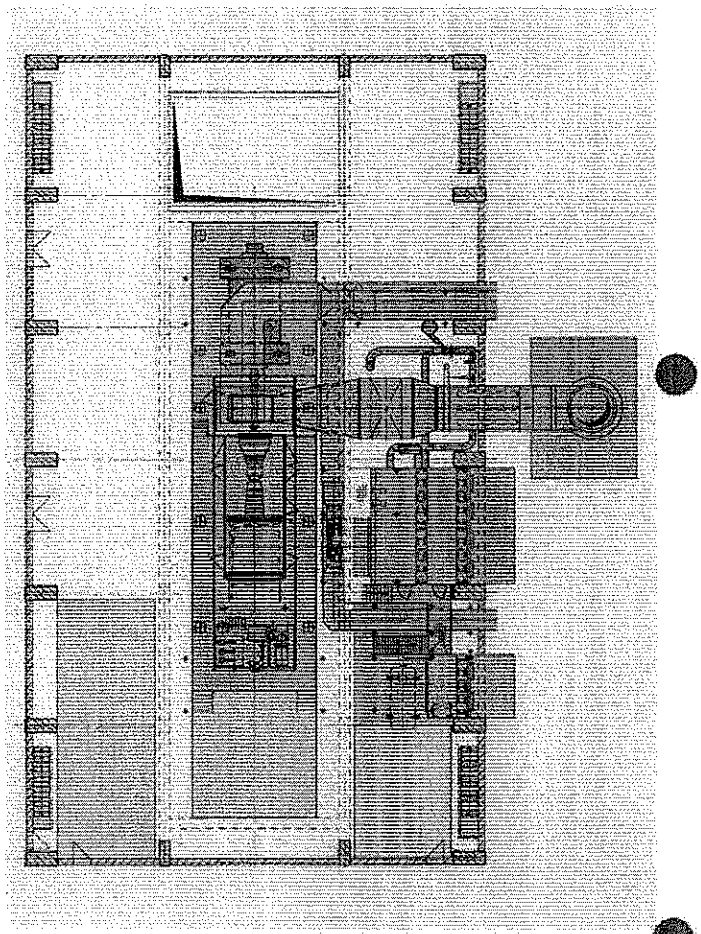
The plant is situated at the heart of Oberhausen-Sterkrade and must therefore satisfy stringent environmental conditions in respect of exhaust gas and acoustic emissions. To achieve maximum cost efficiency, it was planned to incorporate old installation components as far as possible into the new



1

design. The basic concept provided for dismantling of the old helium turbine (Fig. 1) comprising a low-pressure compressor, high-pressure compressor, LP and HP turbines, and its replacement by a type FT8 industrial gas turbine.

This new total concept consists in essence of the existing power house with a waste heat recovery boiler, and the existing heat and power station with its systems and buildings. Virtually all parts of the buildings were re-used in the concept, including the crane installation in the power house (Fig. 2). For the new turbogroup a Siemens KWU electricity generator, which is over 20 years old, was partly overhauled, revamped and re-used. The consortium was responsible for the mechanical aspects of connecting it to the new machine train, and for the aspects of stability and vibration. The foundation underneath the electricity generator was also included in this total concept. The generator remained in its original position



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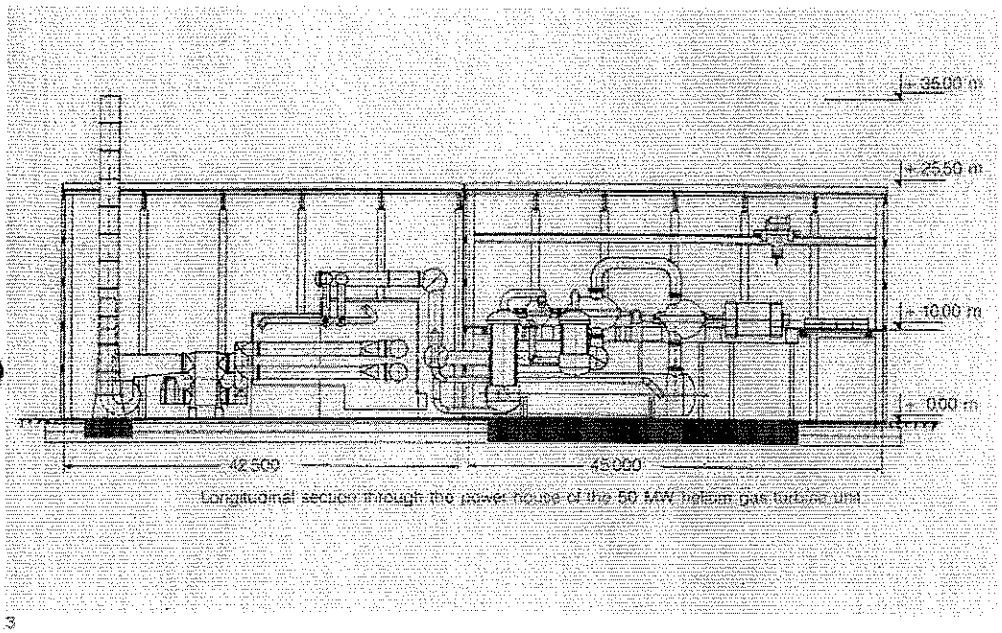
throughout the construction phase, with only the rotor requiring an overhaul and subsequent refitting. The new waste heat recovery boiler together with the air intake filters and exhaust silencer for the gas turbine were erected on the existing 10 m platform.

Fig. 3 shows a longitudinal section through the old turbogroup. Seen to the far right of the power house is the electricity generator, which is directly connected to the LP turbine. The gear train is followed by the HP group, comprising the HP turbine together with the high- and low-pressure compressors.

Lying beneath the turbine is the heat exchanger, preceded by a precooler and intercooler.

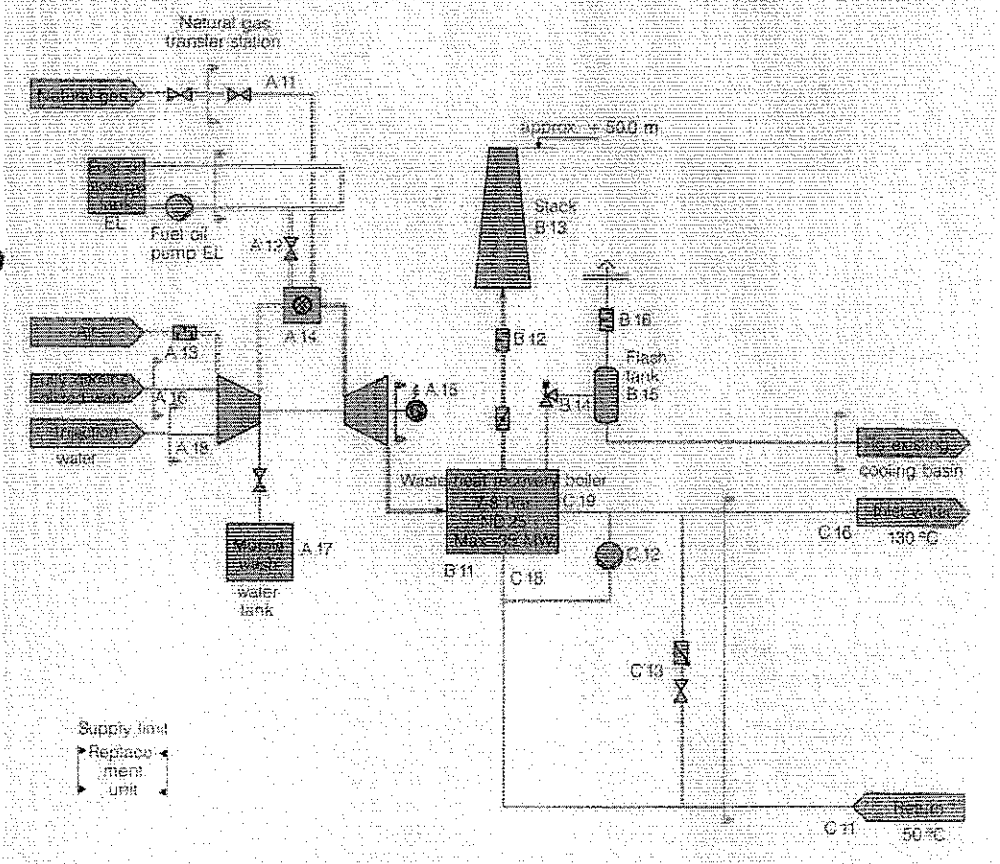
The power house was re-used in its entirety for the new gas turbine unit. In principle all the old turbine casings and heat exchangers in this area of the installation were completely removed, leaving the generator plus foundation and oil supply unit. This concept has permitted the generator main leads to be re-used without modification.

Parts of the old pipework system were also incorporated where possible into the new installation.




Longitudinal section through the power house of the 50 MW heavy gas turbine unit

3




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The exhaust gas generated by the gas turbine at a temperature of approximately 465 °C is routed to a waste heat recovery boiler linked to the Oberhausen district heating supply system.

Fig. 4 shows the connection diagram. The gas turbine unit is rated for an air intake temperature of – 15 to + 30 °C at a relative air humidity of 60 % and an erection height of 37 m.

The existing fuel oil tank and pumping station were used for oil operation, while a new natural gas supply system was installed to supply gas at a pressure of 42 bar.

Thanks to the modern technology embodied in the Dry Low NOx (DLN) combustor, exhaust gas values fall far below those stipulated in the "TA-Luft" technical directives on clean air for natural gas operation, while emissions during fuel oil operation are kept within limits by the injection of water. The exhaust gases from the combustor to drive the power turbine generate 24.4 MW of electricity under the existing boundary conditions. The intake and outlet pressure loss was guaranteed at 7.5 mbar and 18 mbar, respectively.

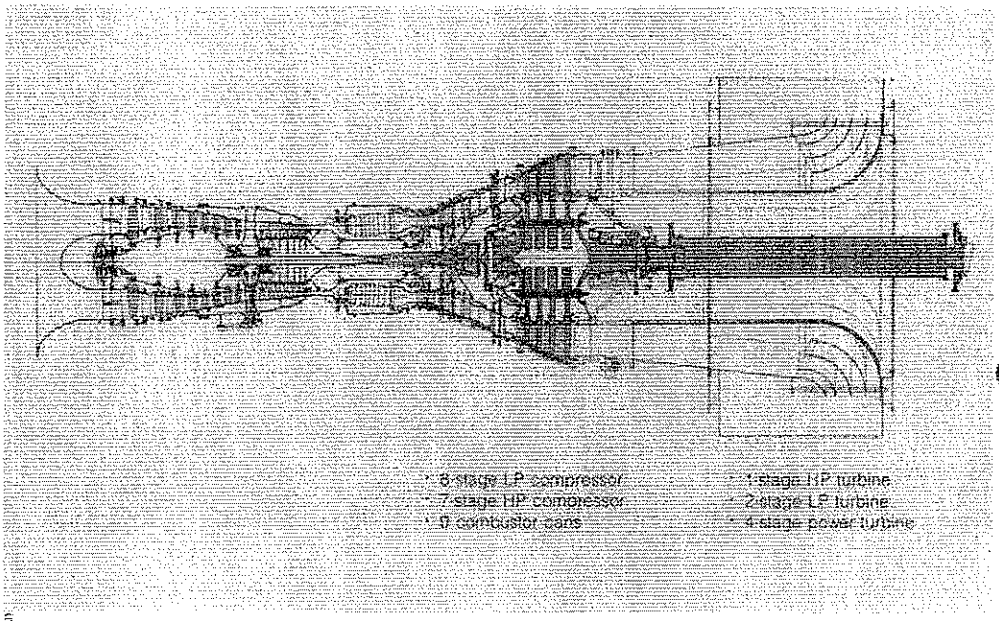
The flue gases of the gas turbine enter the waste heat recovery boiler at a temperature of 440–465 °C with a mass flow rate of 285,000–295,000 kg/h.

The unit can reach synchronous speed in 150 seconds and its rated output on rapid loading in a further 160 seconds, with a guaranteed availability of 96 %.

## Gas turbine

To drive the old generator, GHH BORSIG supplied a type FT8 gas turbine, which offers the ideal driving unit owing to its compact dimensions and extremely low heat rate. The FT8 is a gas turbine developed from the Pratt & Whitney type JT8D aircraft engine. More than 14,000 of these engines have been sold, making it one of the world's most widely used aero engines. This relatively new gas turbine has also benefited from the experience gained with the Pratt & Whitney PW 4000 and PW 2000 engines and the technical advances achieved on these; at this stage, more than 63 units have already been sold for industrial operation.

Like its FT4 predecessor, the FT8 is of modular construction, and is easily installed and dismantled thanks to the consistent use of the Packaging System. The combustor system used allows it to operate on liquid and gas fuels. Since the power turbine of the FT8 can be supplied to operate at 3000 rpm or 3600 rpm and also as a left- or right-handed turbine, it is eminently suitable as a prime mover for existing installations. The gas turbine is pre-erected in a compact form ready for operation on a base and comes completely fitted out for the plant, while the design of




5

the ancillary units on so-called skids offers optimum flexibility for erection on site.

Fig. 5 shows a section through the FT8 gas turbine with its low- and high-pressure compressors and related drive turbines. One feature worthy of special note is the power turbine, which is constructed in four stages. Following the power turbine is the standardized diaphragm coupling, which is connected directly to the old electricity generator. Looking at the weight data of the coupling, the technological approach derived from aircraft engine construction is naturally of interest compared with conventional power station applications. The modular structure of the FT8 facilitates swift assembly and disassembly of the components for maintenance purposes, making it possible to exchange its gas generator in just eight hours, for example. In the event of damage this modular system offers the operator an essential safeguard with regard to plant availability.

## Boiler

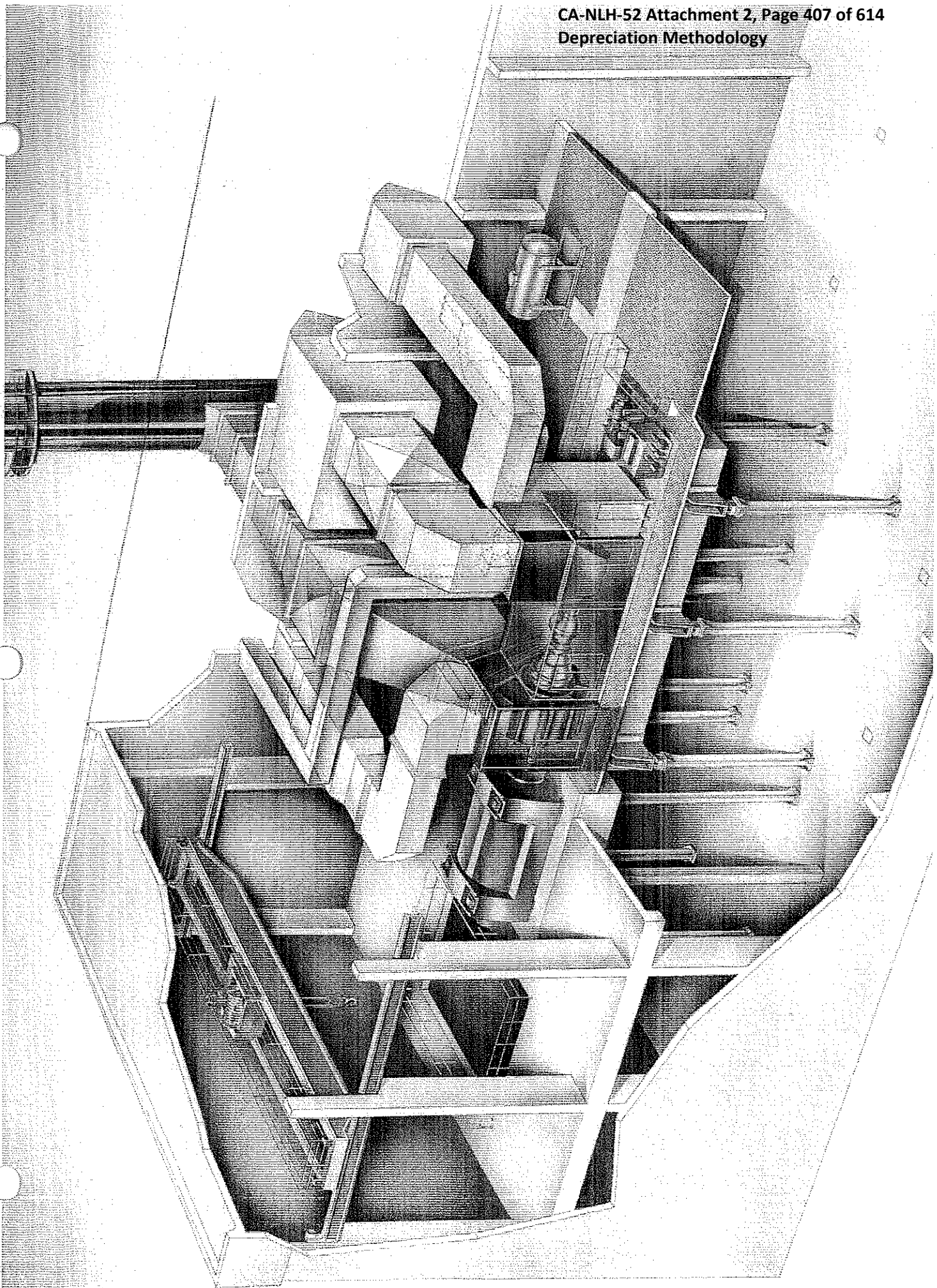
To increase the overall efficiency of the installation to 86% when firing it using natural gas and to 78% during oil operation, Deutsche Babcock Anlagen GmbH and Deutsche Babcock Omnical Industriekessel GmbH supplied the waste heat recovery facility (Fig. 6).

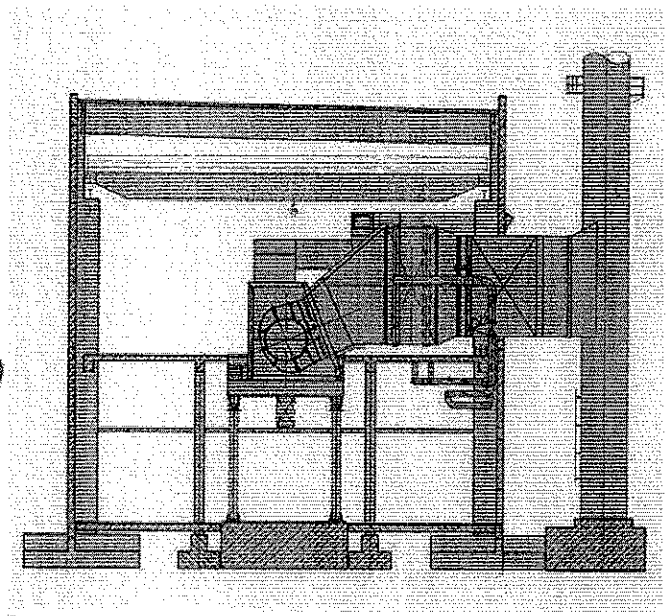
With a return temperature of 50 °C and a variable inlet temperature of 80–130 °C, this provides for 35 MW of thermal power to be tapped and fed into the Oberhausen district heating grid.

The gas turbine exhaust gases are routed to the heat exchanger through a collector box. Integral baffle plates ensure that the gases act evenly on the heating surface.

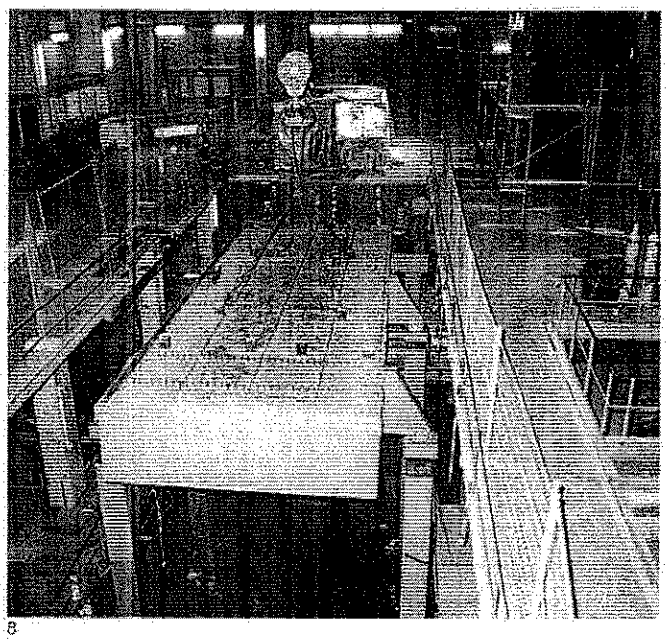
The heat exchanger is designed as a self-supporting vertical structure consisting of two modules. The finned-tube heating surface is suspended between the inlet and return headers, making it possible to dispense with both perforated plates, which ensure that the tubes are correctly spaced in relation to one another, and antinoise plates in the tube lanes to suppress vibrations. The waste heat recovery boiler is connected in a countercurrent arrangement.

To protect the heating surfaces, the return temperature was raised to 65 °C in natural gas operation by the addition of inlet water, a recirculation pump being installed for this purpose. When operating the gas turbine using oil as the fuel, the water injection temperature for the boiler has to be increased to 90 °C using the hot water recirculation pump. The boiler outlet temperature is a constant 130 °C, while the temperature of the flue gas after leaving the boiler lies between 107 and 119 °C.

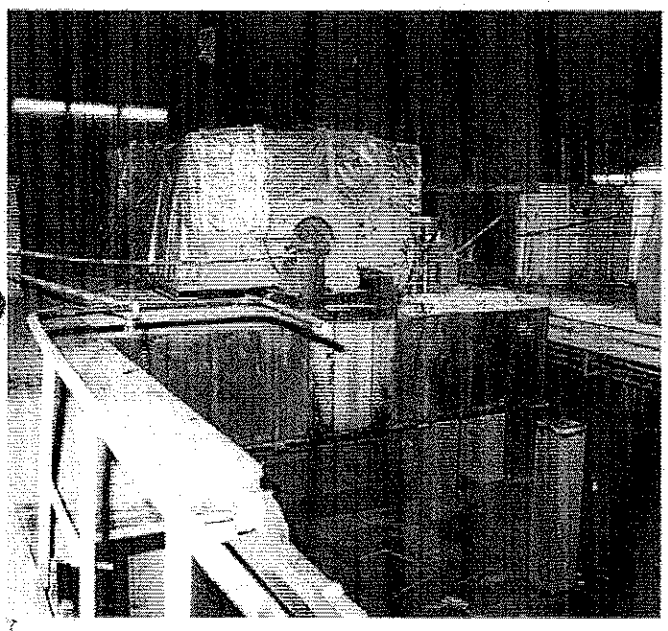




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In order to guarantee rapid start times of five minutes at peak loads, the boiler is kept warm during periods when the overall installation is shut down, the flue gas path being closed by means of a sealing damper behind the heating surface.

This is followed by the silencer on the flue gas side, which is rated for an immission pressure level of 35 dB(A) at a distance of 50 m from the base of the stack. The installation is provided with combined heat and sound insulation extending halfway up the silencer casing. The flue gases enter the double-shell stack via a flue gas duct.

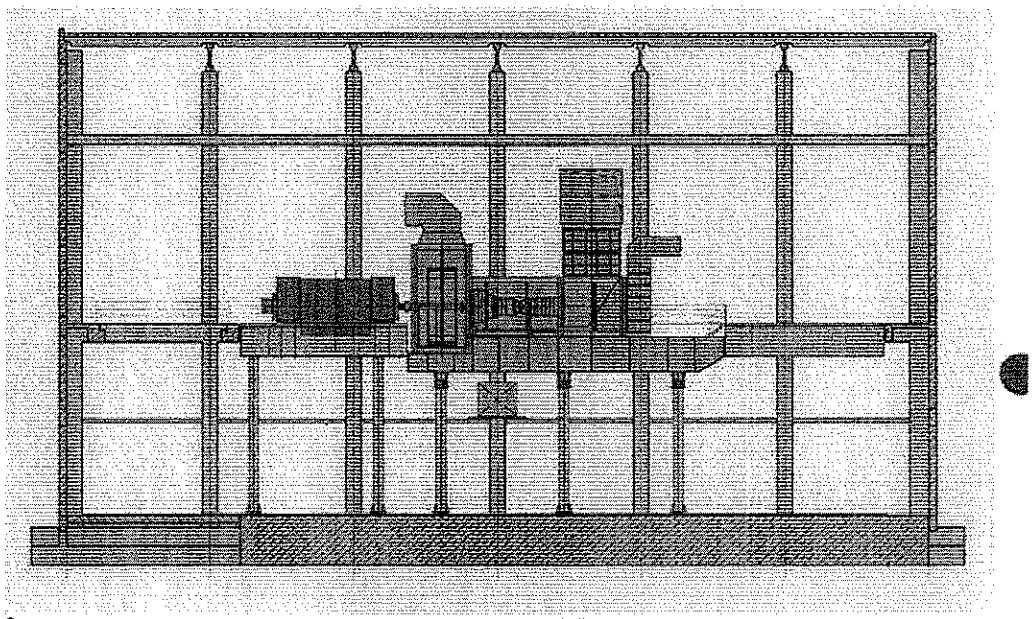
## Layout to include the old components

A general problem which arises when revamping old units is of course the difficulty of obtaining drawings which are more than 20 years old. EVO was able to supply extraordinarily good engineering data, which was advantageous with regard to the very tight overall schedule. As already mentioned, the total concept allows for the incorporation of as many parts as possible of the old machine foundations and sole plates into the new foundation design. The original foundation for the helium gas turbine could not be re-utilized; although the shaft centreline of the FT8 package is at an extremely favourable height for cases such as this, a new foundation had to be constructed at greater depth for the gas turbine.

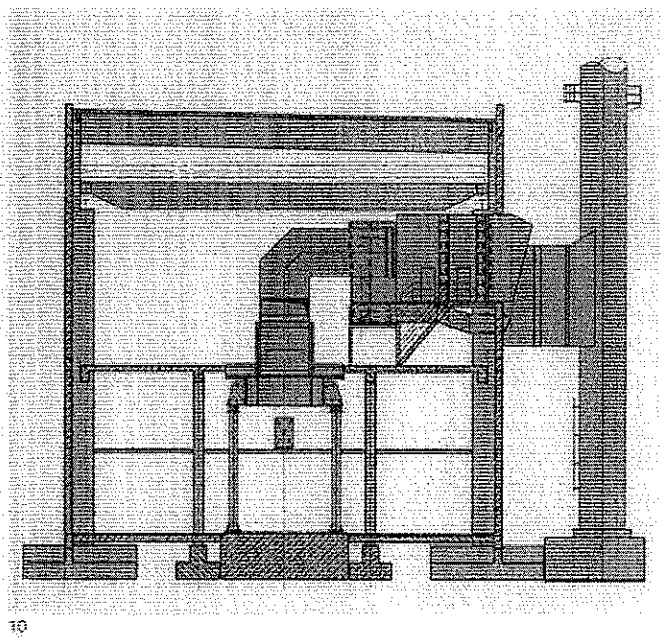
Fig. 7 shows the power house during the demolition work. The unaltered section of the electricity generator foundation can be seen clearly here after the front parts of the foundation had been cut away, as can the foundation columns, which were all re-used following minor modifications to accommodate the new column heads.

Fig. 8 shows the new gas turbine foundation being positioned on the column heads. This photograph also depicts the waste heat recovery boiler, which was erected in advance. The extremely high load-bearing capacity of the power house naturally offered considerable advantages here.

Fig. 9 is a section through the new installation with the old electricity generator and new gas turbine set. The generator was left unchanged on its foundation throughout the construction period, only the generator rotor being removed and overhauled. As the top view (Fig. 2) shows, it was possible to take over the whole of the old power house virtually without modification. The existing power house also proved highly satisfactory for the installation of the air filter systems for the gas turbine and for enclosure ventilation. To do this it was only necessary to break through the wall and add an extra steel construction



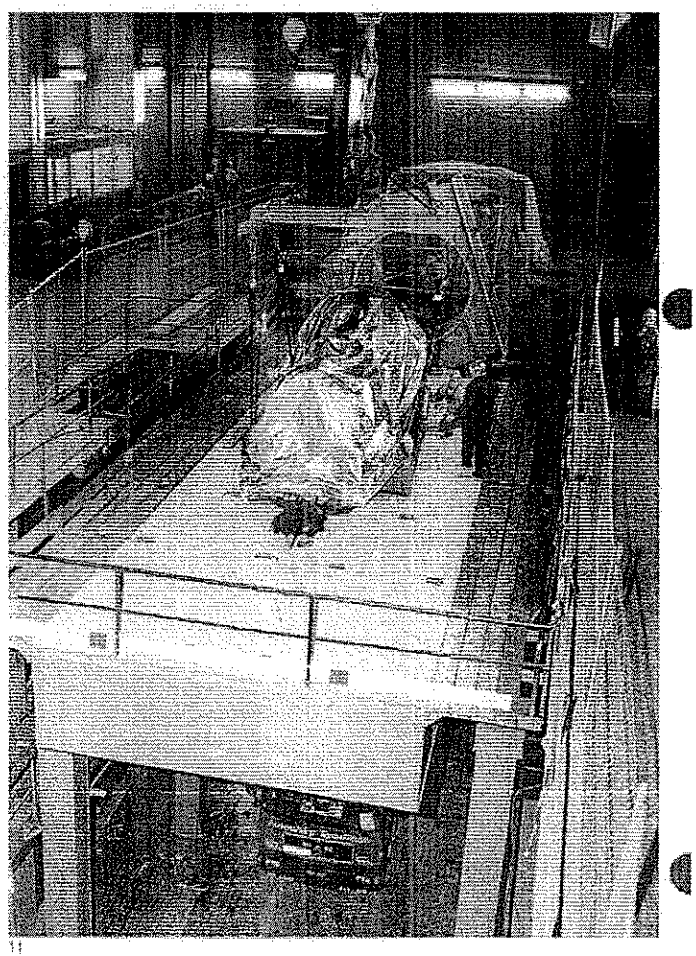
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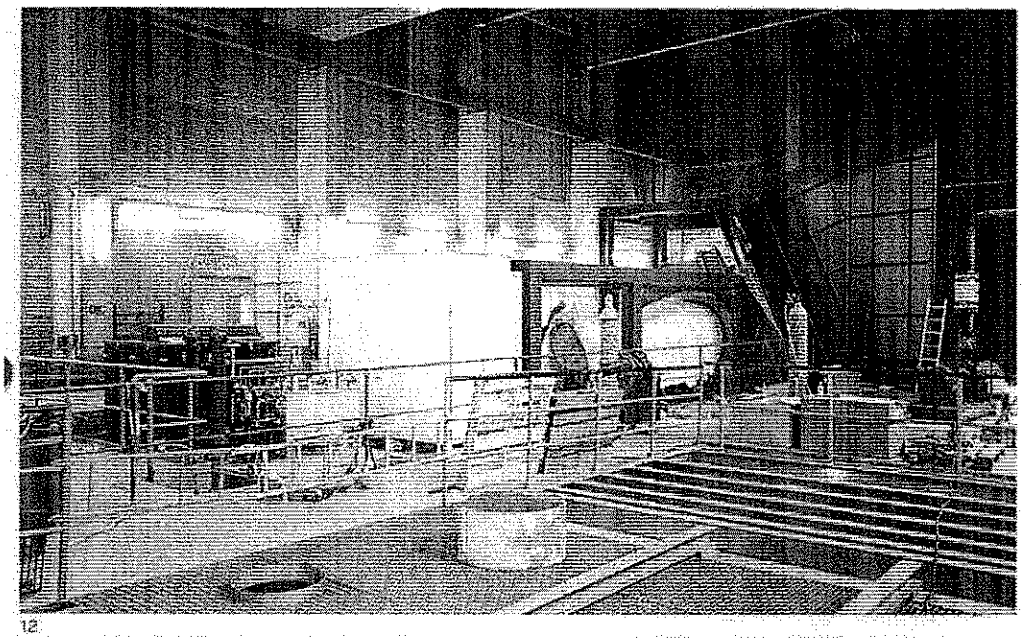
10

in the existing power house wall (Fig. 10). Since the new gas turbine unit takes up considerably less space than the old unit, large areas around the 10 m platform had to be covered.

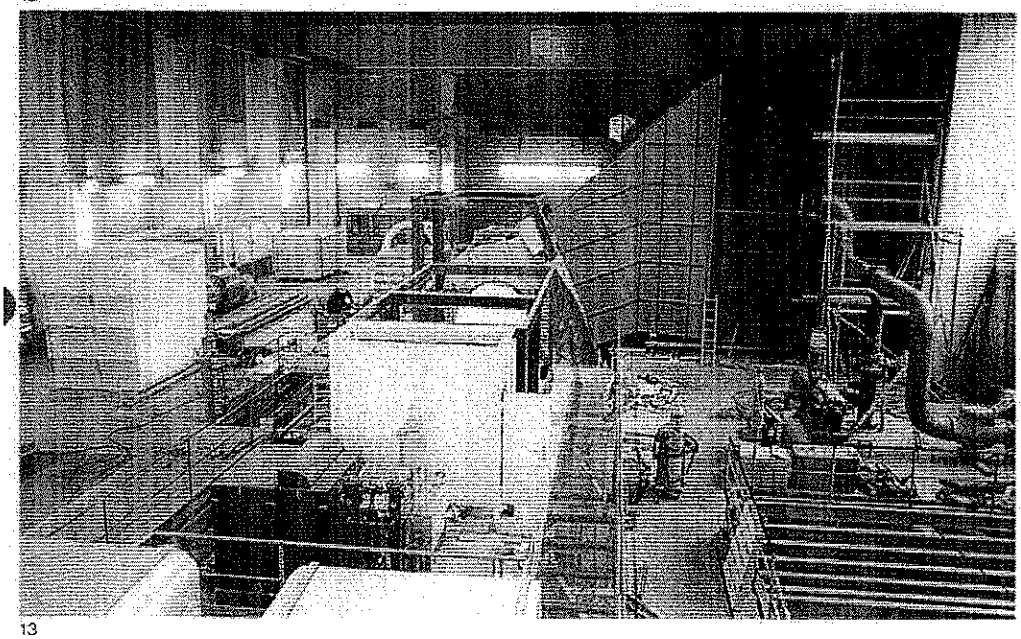
As can be seen from the sectional view, the generous height of the old power house crane pro-



11



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13

vided the optimum conditions for erecting both the boiler and the ancillary units, thereby guaranteeing accessibility for maintenance and overhaul purposes.

### Acoustic emissions

The inner-city location of the power station means that stringent, contractually safeguarded conditions were imposed with regard to sound. The sound projection outwards may not exceed 35 dB(A) at a distance of 50 m from the power house wall, while regulations permit an acoustic value of 80 dB(A) inside the power house.

### Process control system

In the light of the demands made today on such facilities, the total complement of process control equipment accounts for a sizeable share of an installation of this kind. The process control concept enables the new gas turbine unit to be operated unsupervised from a central control station in Oberhausen. EVO placed a separate order with Siemens for the integration of this concept into the existing overall system.

### Electricity generator

Re-utilization of the 50 MW electricity generator was an essential factor in this total concept. The generator has only 25,000 operating hours behind it and is in excellent condition. The generator rotor was overhauled, and the generator bearings on the drive side were fitted with an axial auxiliary bearing.

Figs. 11 to 13 show the gas turbine unit during the erection phase from 15 October to 01 December 1995. The installation was commissioned on schedule on 15 December 1995.

A large proportion of the gas turbine units now in use consist of old facilities which have been revamped or modified. Revamping old units to provide ultra-modern, efficient gas turbine systems constitutes an extremely cost-effective concept for operators.

# APPENDIX 8
# BRUSH NEW GENERATOR PROPOSAL

**Hearn, Bill G.**

**Subject:** FW: Newfoundland & Labrador Hydro - Brush Generators

**Attachments:** PWPS_STD_13_8KV Set.pdf; ET2049.pdf; ET2541 Trans Pac.pdf; ET1147A.jpg; Industrial Power SM0000242E.pdf

**From:** Derek King [mailto:Derek.King@houston.rm.fki-et.com]
**Sent:** Friday, November 16, 2007 2:38 PM
**To:** King, Brian; pierre.bovon@ca.manturbo.com
**Cc:** Mike.Watkins
**Subject:** Newfoundland & Labrador Hydro - Brush Generators

Brian/Pierre - I have been copied a recent email string on your project needs.

The enquiry was interpreted as a requirement for on site plant rebuild and no process to offer a new machine was initiated.

Brush currently manufactures a series of double ended generators for the Pratt & Whitney Twin Pac FT8-3 program and has delivered more than 80 units. P&W put the generator into their enclosure which includes the filters, but Brush could engineer an enclosure with top filter house similar to your existing machine. There would need to be careful consideration of the major interfaces to make the current machine fit, but thinking engineers could achieve that objective. Clients A/E would need to lead those integration efforts. Brush can assist with ideas, and where we would incorporate practical generator configuration changes (from present day standard) to best fit the project.

A set of standard 13.8Kv 60Hz data is attached here for your review - if your project needs special reactance's then let us know the target parameters. Delivery time would be ~ 12/14 months from completion of the drawing approval process.

Rough ball park costs for the new generator are:

a) BDAX7-290 ER with loose AVR. Base double ended generator open ventilated. US $ 2.5M
b) Top mounted TEWAC cooler assembly. US $250K
c) Option for alternate top mounted - replaceable pad type standard filter house US $300K
d) Acoustic and weather protecting canopy to enclose either TEWAC generator - or direct air cooled machine. (Filter house in this case would then be roof mounted) - US $ 250K

Typical layout drawings for these generators are attached here. Note that ET1147 shows a CANOPY outline on a smaller TEWAC machine which would be of a length to enclose the new generator coupling face to face.

These budget numbers are strictly for guidance and do not cover special features that may be required for the project. They do not include Line or Neutral cubicles or off generator support systems - external radiators, water system, oil services, clutches etc, but Brush can offer or work with vendors for those if needed.

I hope this information is of help to your considerations - please let us know if we need to start a firm enquiry, and focus on your particular requirements.

Regards Derek
This message from Derek King

BRUSH Turbogenerators Inc. Houston
Tel: +1 281 580 1314 X208
Fax: +1 281 580 5801

Mobile: +1 281 923 1314
Email: derek.king@houston.rm.fki-et.com
Website: www.brush.eu

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BRUSH Turbogenerators Inc. 15110 Northwest Freeway, Suite 150, Houston, Texas .77040 USA.

BRUSH ELECTRICAL MACHINES LTD

BRUSH ELECTRICAL MACHINES LTD

# ELECTRICAL DATA SHEET

**P O Box 18, Falcon Works, Loughborough, Leics. LE11 1HJ, England**
**Telephone: +44 (0) 1509 611511 Telefax: +44 (0) 1509 612345 E-mail: Sales@bem.fki-eng.com**

## 1. RATING DETAILS

| | | |
|---|---|---|
| 1.1 | Frame size | BDAX 7-290ER |
| 1.2 | Terminal voltage | 13.80 kV |
| 1.3 | Frequency | 60 Hz |
| 1.4 | Speed | 3600 RPM |
| 1.5 | Power factor | 0.850 |
| 1.6 | Applicable national standard | ANSI C50.14 |
| 1.7 | Rated air inlet temperature | 15.0 °C |
| 1.8 | Rated output | 60.500 MW, 71.176 MVA |

## 2. PERFORMANCE CURVES

| | | |
|---|---|---|
| 2.1 | Output vs air inlet temperature | H.E.P. 17660 |
| 2.2 | Reactive capability diagram | H.E.P. 17661 |
| 2.3 | Efficiency vs output | H.E.P. 17662 |
| 2.4 | Open and Short circuit curves | H.E.P. 17663 |
| 2.5 | Permitted duration of negative sequence current | H.E.P. 1216 |

## 3. REACTANCES

| | | |
|---|---|---|
| 3.1 | Synchronous reactance, $X_{d(i)}$ | 235% |
| 3.2 | Saturated transient reactance, $X'_{d(v)}$ | 20.0 % ±15.0 % |
| 3.3 | Saturated sub transient reactance, $X''_{d(v)}$ | 14.4 % ± 15.0 % |
| 3.4 | Unsaturated negative sequence reactance, $X_{2(i)}$ | 17.6 % |
| 3.5 | Unsaturated zero sequence reactance, $X_{o(i)}$ | 9.5 % |
| 3.6 | Short circuit ratio | 0.47 |

**Notes:**

1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.

**Date:** 4-Apr-2001

**Ref:** 110134/16/612S/112R

BRUSH ELECTRICAL MACHINES LTD Methodology

# ELECTRICAL DATA SHEET - CONTINUATION

BDAX 7-290ER , 60.500 MW, 0.850 pf, 13.80 kV, 60 Hz

## 4. RESISTANCES AT 20°C

| | | |
|---|---|---|
| 4.1 | Rotor resistance | 0.138 ohms |
| 4.2 | Stator resistance per phase | 0.0033 ohms |

## 5. TIME CONSTANTS AT 20°C

| | | |
|---|---|---|
| 5.1 | Transient O.C. time constant, $T'_{do}$ | 9.7 seconds |
| 5.2 | Transient S.C. time constant, $T'_{d}$ | 0.66 seconds |
| 5.3 | Sub transient O.C. time constant $T''_{do}$ | 0.05 seconds |
| 5.4 | Sub transient S.C. time constant, $T''_{d}$ | 0.04 seconds |

## 6. INERTIA

| | | |
|---|---|---|
| 6.1 | Moment of inertia, $WR^2$ (See note 2) | 990 $Kg.m^2$ |
| 6.2 | Inertia constant, H | 0.99 kW.secs/KVA |

## 7. CAPACITANCE

| | | |
|---|---|---|
| 7.1 | Capacitance per phase of stator winding to earth | 0.18 Microfarad |

## 8. EXCITATION

| | | |
|---|---|---|
| 8.1 | Excitation current at no load, rated voltage | 325 amps |
| 8.2 | Excitation voltage at no load, rated voltage | 44 volts |
| 8.3 | Excitation current at rated load and P.F. | 952 amps |
| 8.4 | Excitation voltage at rated load and P.F. | 185 volts |
| 8.5 | Inherent voltage regulation, F.L. to N.L. | 35 % |

**Notes:**

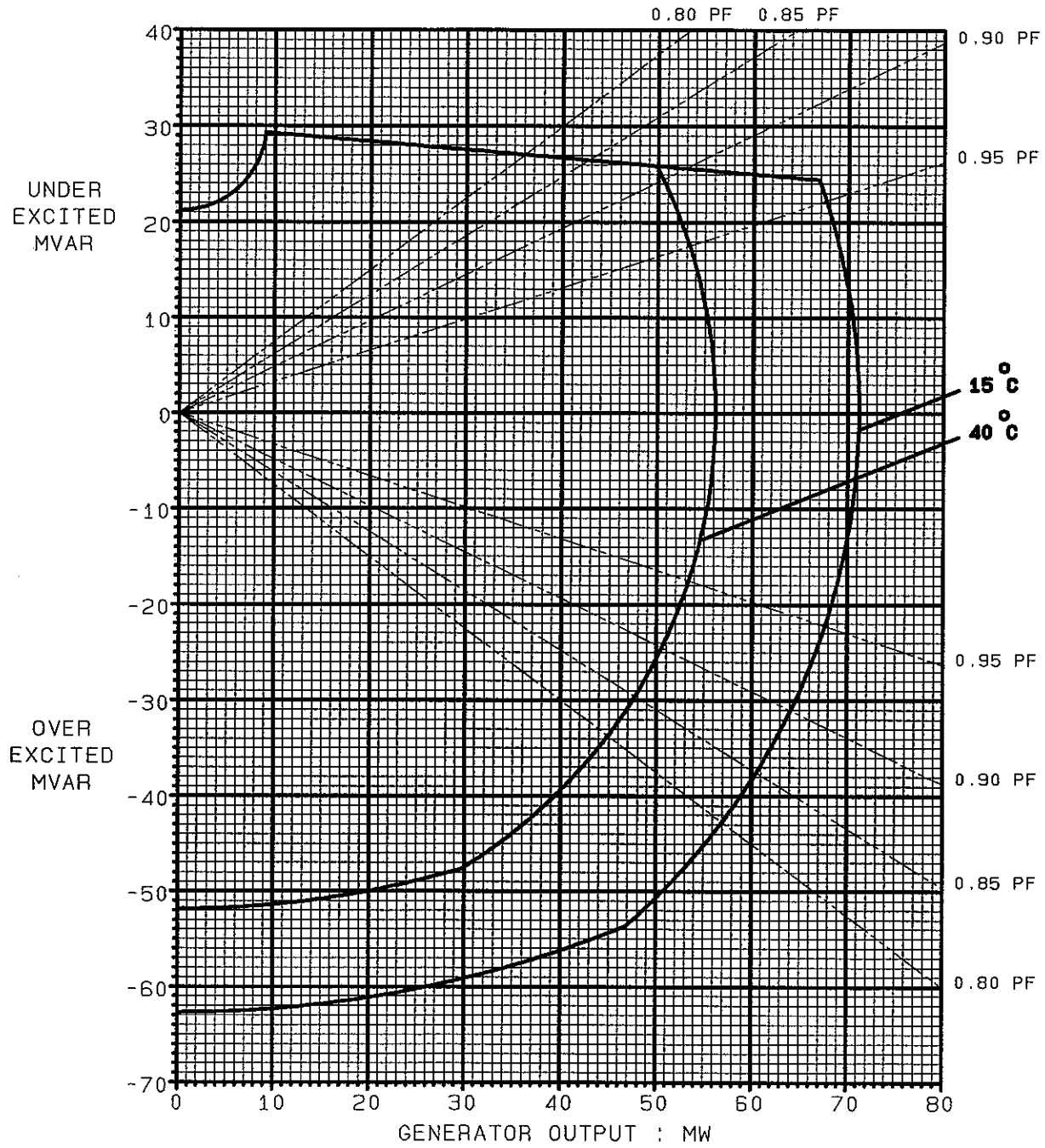
1. The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.
2. The rotor inertia value may vary slightly with Generator/turbine interface. In the event of conflict, the figure quoted on the rotor geometry drawing takes precedence.

**Date:** 4-Apr-2001

**Ref:** 110134/16/612S/112R

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17661

# GENERATOR CAPABILITY DIAGRAM




BDAX 7.290R
13.80KV, 3Ph, 60.Hz.

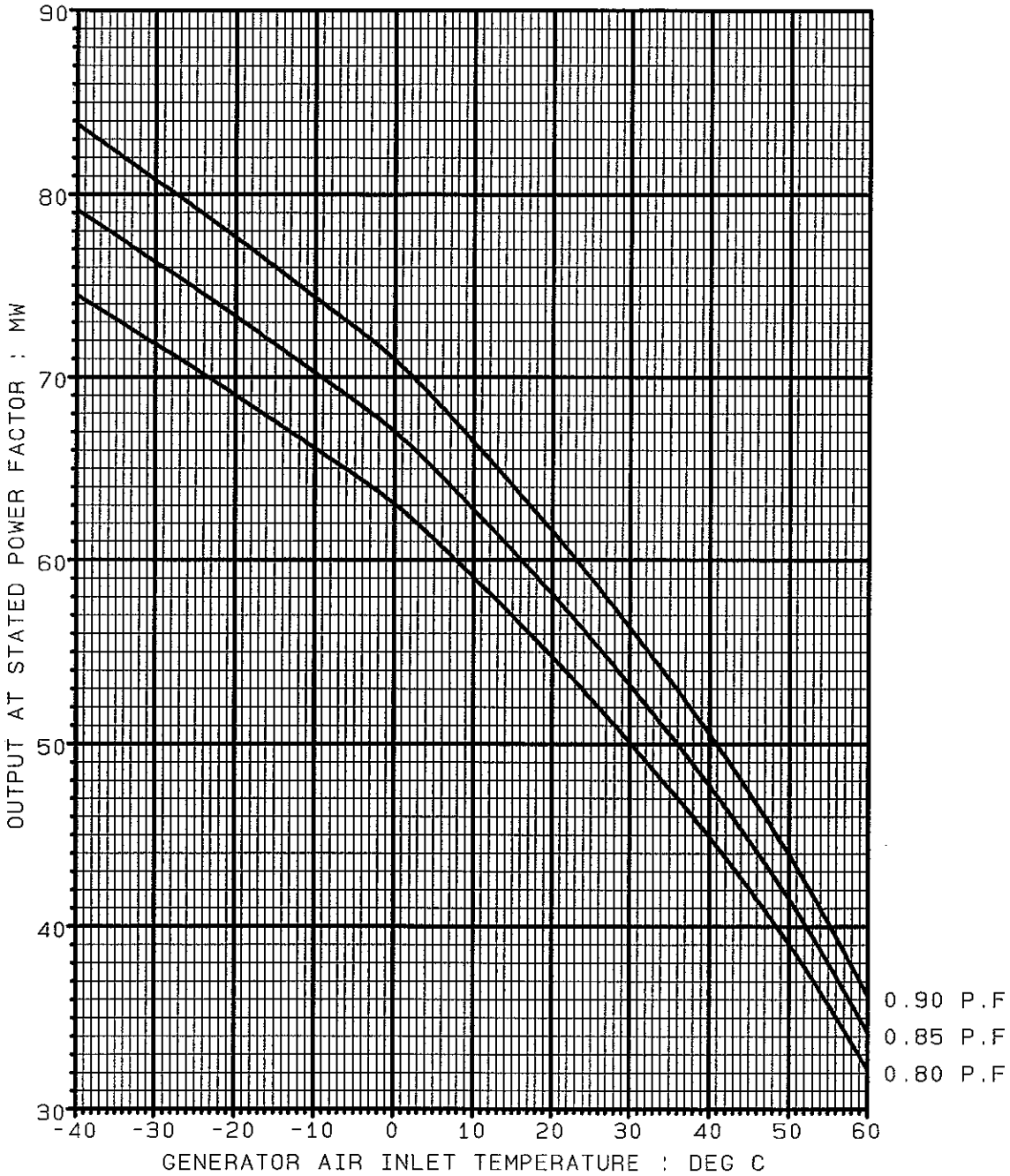
Up to 1000. meters ASL

IN ACCORDANCE WITH
ANSI C50.14.
Class B temperatures.
Curves show base outputs.
Peak outputs are 8% higher.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17660

## VARIATION OF GENERATOR OUTPUT WITH AIR INLET TEMP

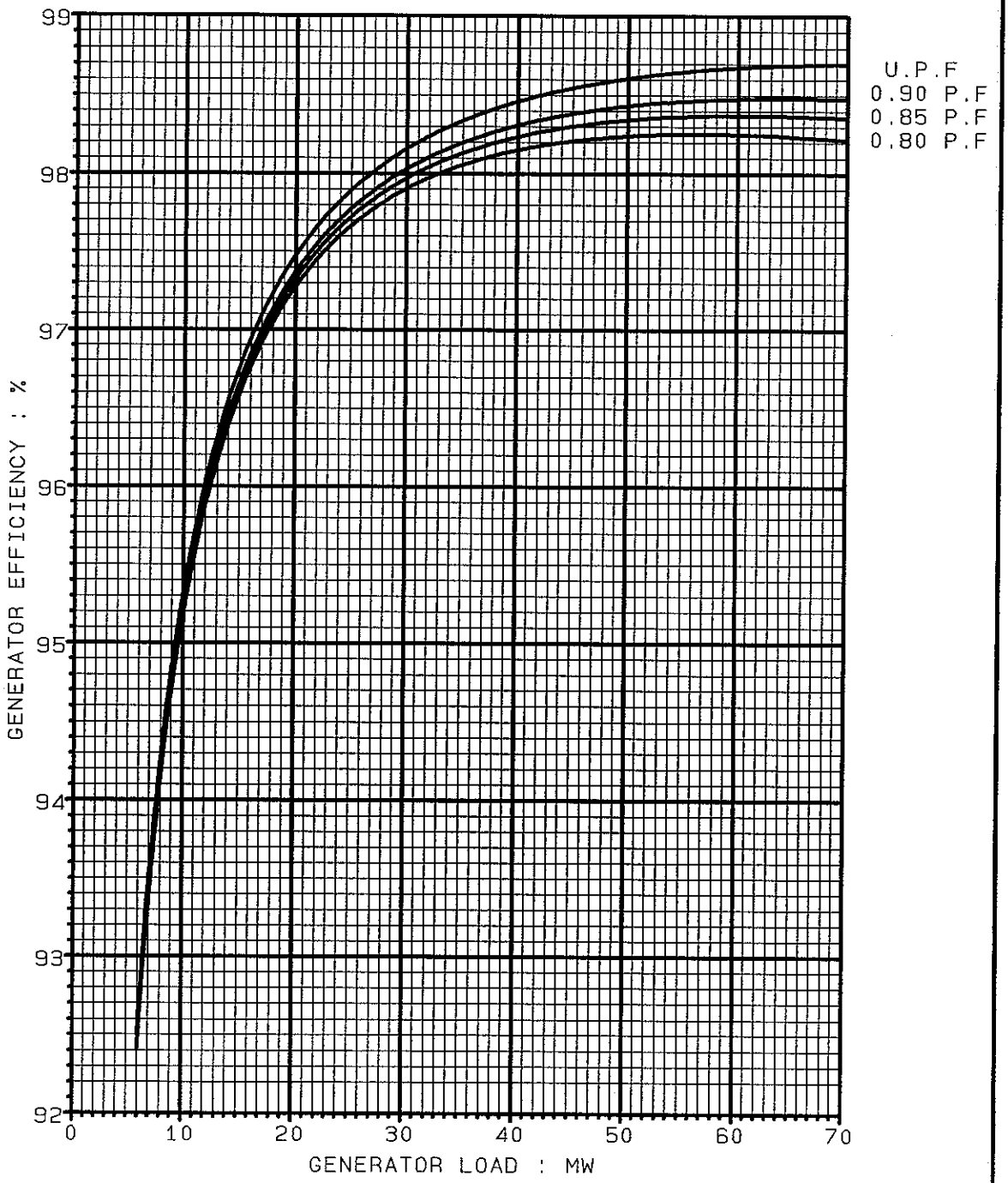



| | |
|---|---|
| BDAX 7.290R | IN ACCORDANCE WITH |
| 13.80KV, 3Ph, 60.Hz. | ANSI C50.14. |
| | Class B temperatures. |
| Up to 1000. meters ASL | Curves show base outputs. |
| | Peak outputs are 8% higher. |

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17662

## VARIATION OF GENERATOR EFFICIENCY WITH LOAD




BDAX 7.290R
13.80KV, 3Ph, 60.Hz.

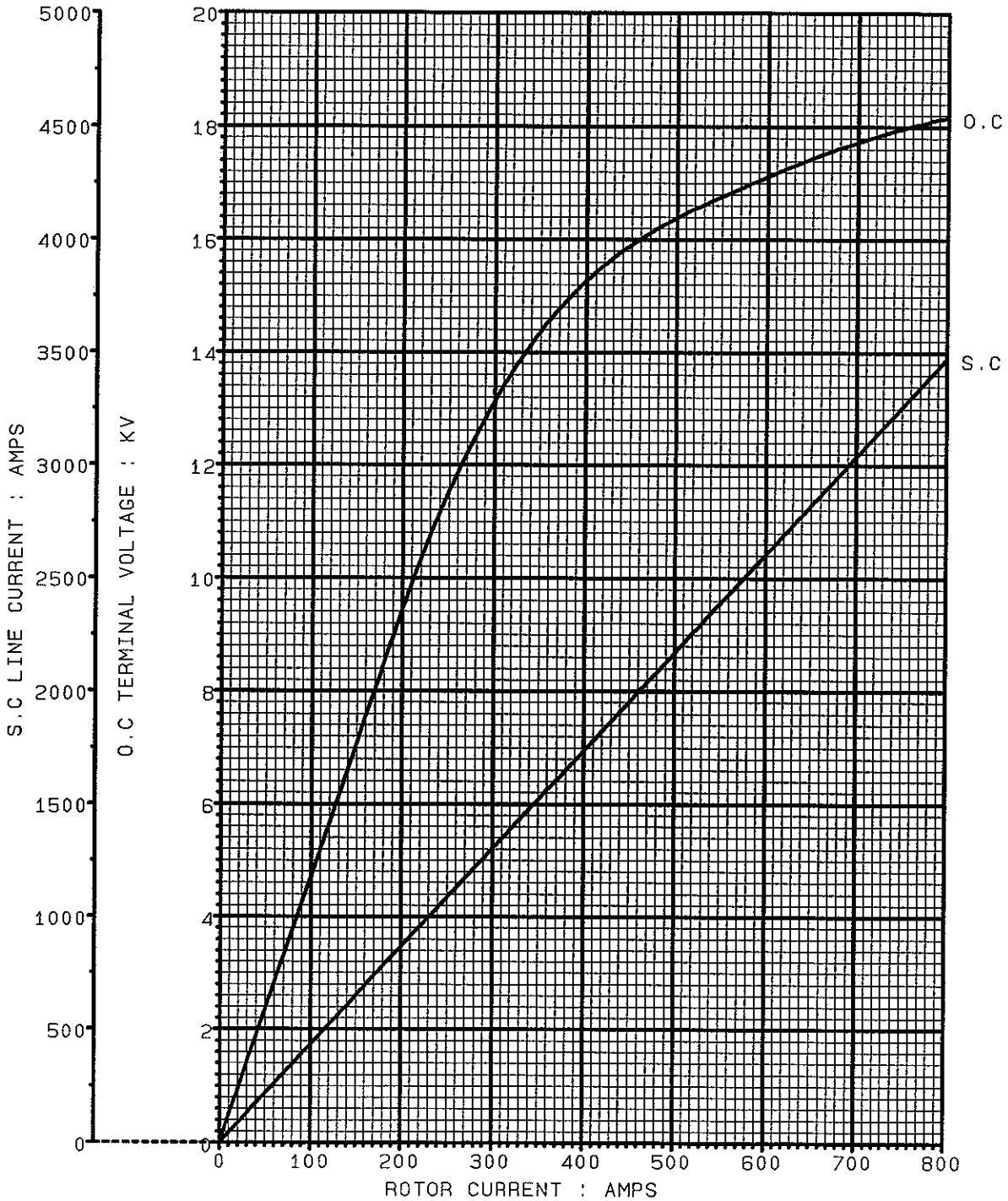
Efficiencies shown are calculated and subject to tolerance as I.E.C 34.1

Minimum efficiencies are 0.1(100-calculated efficiency)% lower.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 17663

## OPEN CIRCUIT AND SHORT CIRCUIT CHARACTERISTIC



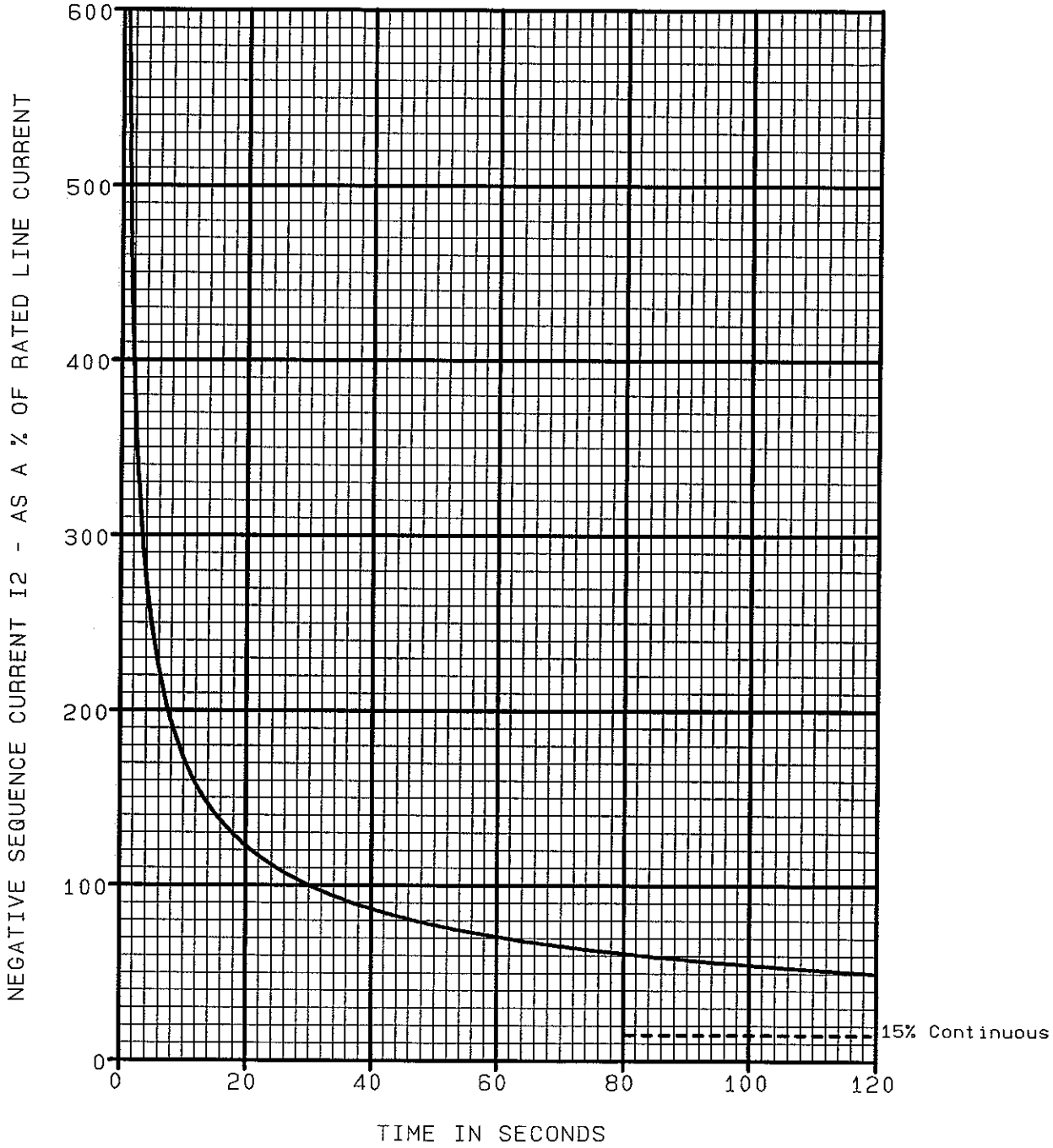

BDAX 7-290R
3Ph, 60.Hz, 3600. RPM.

Issue No. 1: 9-Nov-2000

BRUSH ELECTRICAL MACHINES LTD. H.E.P 1216

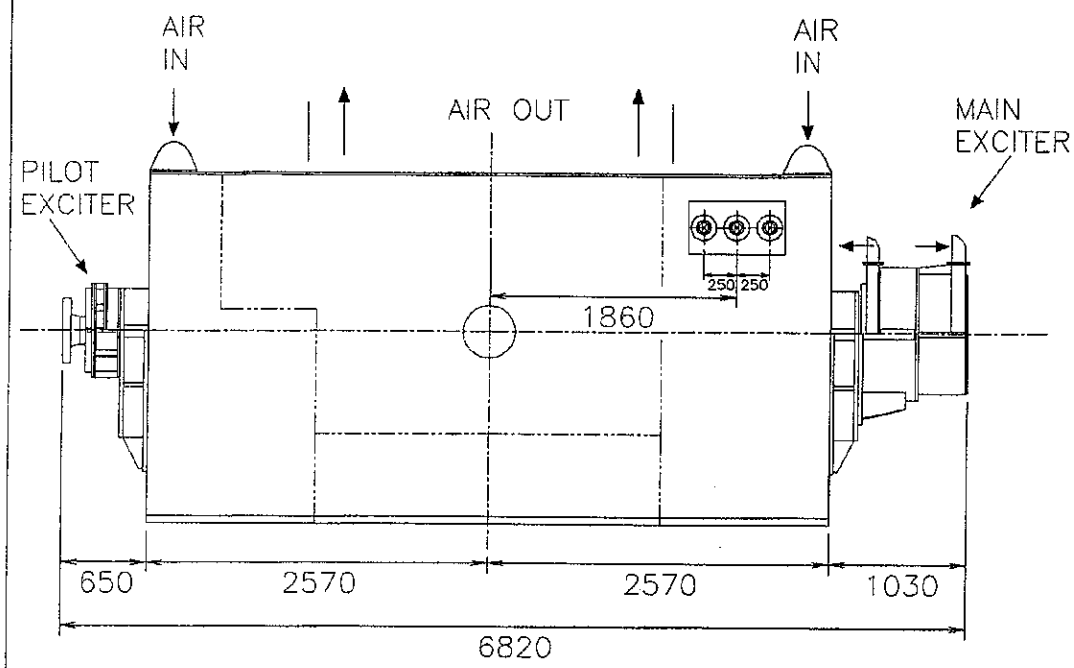
# PERMISSIBLE DURATION OF NEGATIVE SEQUENCE CURRENT

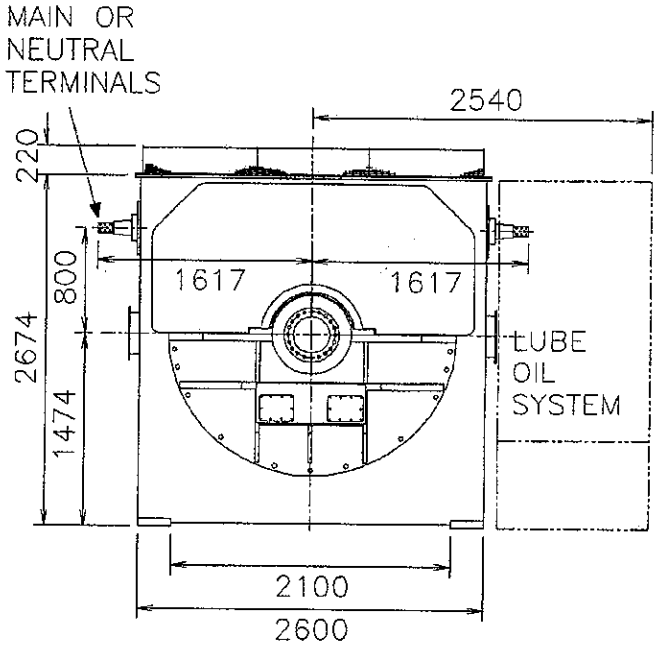
$I_2^2 t - 30$




NOTE: For continuous operation rated current must not be exceeded in any one phase.

Issue No. 9: 25-Feb-1993




VIEW ON NON EXCITER END

APPROXIMATE WEIGHTS

| | | |
|---|---|---|
| STATOR | = | 53340 Kg |
| ROTOR AND EXCITER ARMATURE | = | 14970 Kg |
| TOTAL GENERATOR | = | 74810 Kg |
| OIL SYSTEM | = | 2200 Kg (DRY) |

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BRUSH ELECTRICAL MACHINES
P.O. BOX 18 LOUGHBOROUGH
LEICESTERSHIRE LE11 1HJ

| | | | |
|---|---|---|---|
| DATE | 17/11/97 | DR'N | A NEEDHAM |
| CIRCULATION | | N/A | |
| ADDL PRINTS | | NONE | |
| AUTOSKETCH | | SHT 1 OF 1 | |

TENDER OUTLINE
BDAX 7-290 E(R)

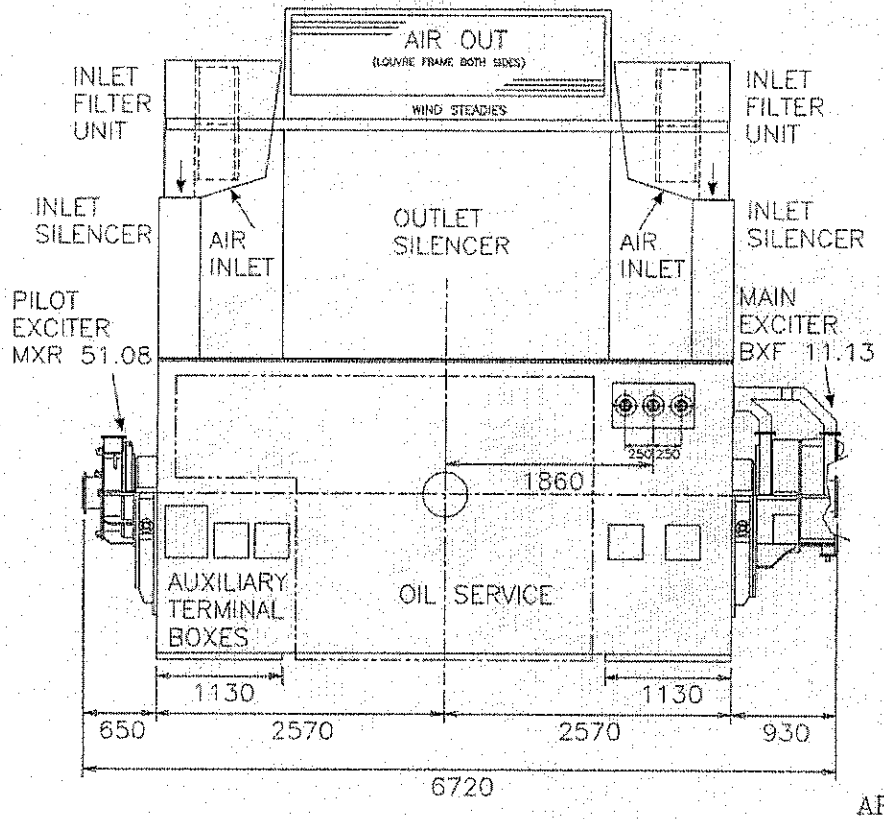
CODE

ET 2049 ISS A

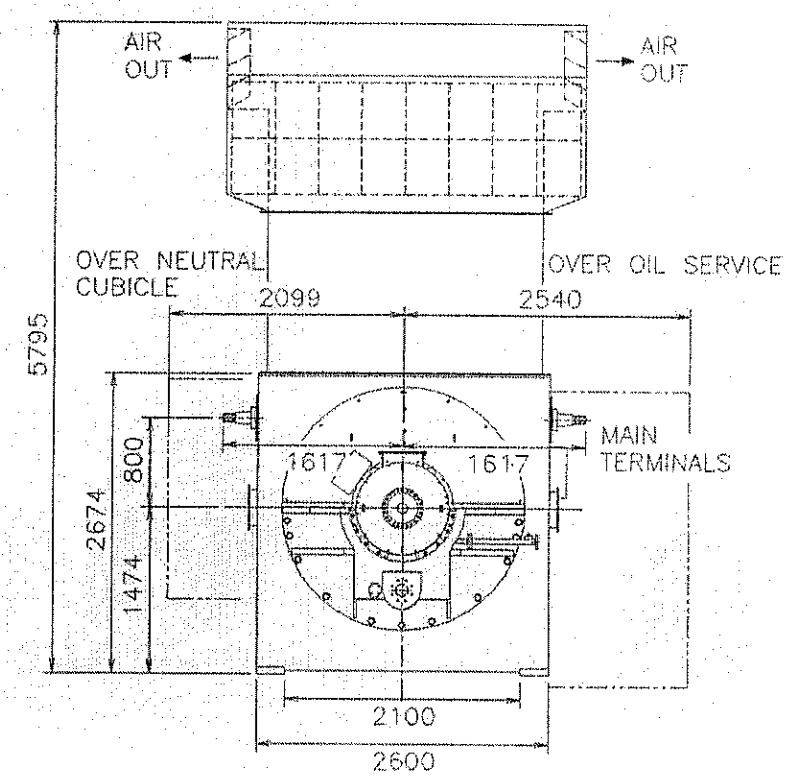
| SCALE | NTS | DEPT | DAX |
|---|---|---|---|

FIRST ANGLE PROJECTION

PRELIMINARY




FILTER LAYOUT PLAN VIEW




VIEW ON NON EXCITER END

APPROXIMATE WEIGHTS

| | | |
|---|---|---|
| STATOR | = | 53840 Kg |
| ROTOR AND EXCITER ARMATURE | = | 14822 Kg |
| TOTAL GENERATOR ONLY | = | 73360 Kg |
| LUBE OIL MODULE (DRY) | = | 2200 Kg |
| FILTERS & DUCTS (ALL) | = | 4500 Kg |

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BRUSH
BRUSH ELECTRICAL MACHINES LTD
P.O. BOX 18 LOUGHBOROUGH
LEICESTERSHIRE LE11 1HJ

| | | | |
|---|---|---|---|
| ORIGINALLY DRAWN | | | |
| DATE | 14/12/00 | SIG | A N |
| LATEST MODIFICATION | | | |
| DATE | __/__/00 | SIG | _ _ _ |
| AUTOSKETCH | SHT 1 OF 1 | CODE | |

# TENDER OUTLINE
# BDAX 7-290ER

ET 2541 ISS A

| | | | |
|---|---|---|---|
| SCALE | NTS | DEPT | ENG |

FIRST ANGLE PROJECTION

Shelter frame - shows enclosure canopy only!

ET 1147

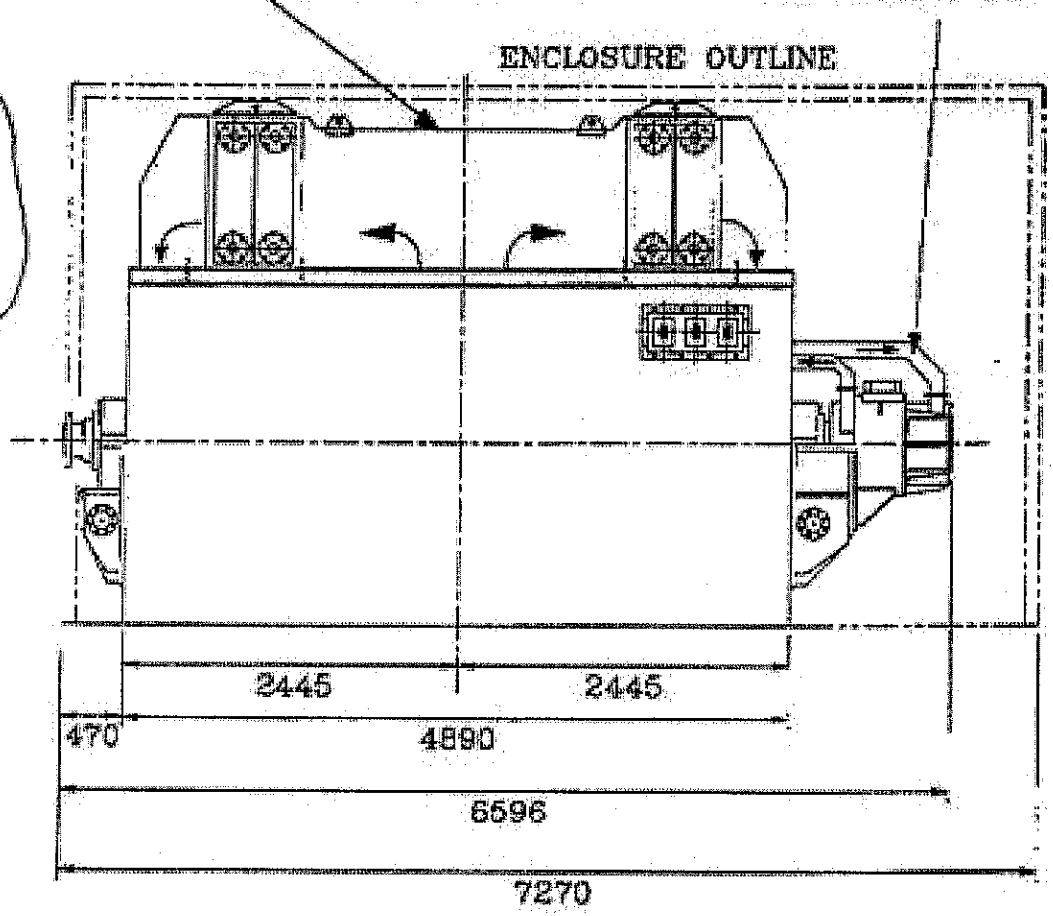
BDAX 7-265E(R)H

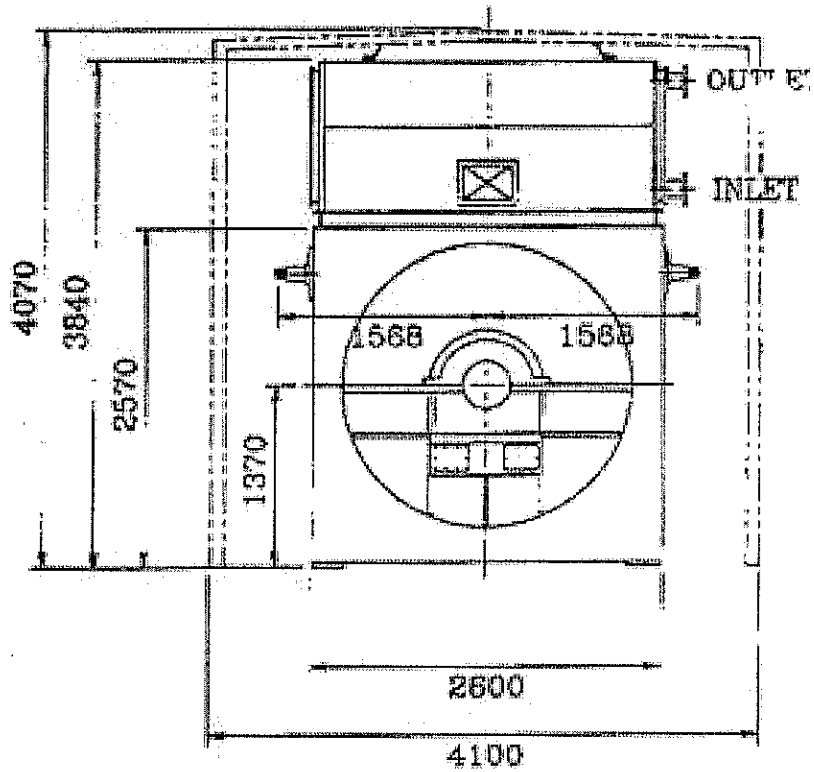
TENDER OUTLINE

FOUR NEST HEAT EXCHANGER.

MAIN & PILOT EXCITER.

ENCLOSURE OUTLINE




VIEW ON NON EXCITER END.

APPROXIMATE WEIGHTS

| | | |
|---|---|---|
| STATOR | = | 50590 Kg |
| ROTOR AND EXCITER ARMATURE | = | 13461 Kg |
| TOTAL GENERATOR | = | 73890 Kg |
| TOTAL ENCLOSURE | = | 10400 Kg |

ET 114/

A NEEDHAM 12/11/91

ISSUE A1

BRUSH

# INTERNATIONAL SALES & SUPPORT LOCATIONS


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Fax: +1281 5805801
Email: sales@houston.rm.fki-et.com

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BRUSH


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Netherlands
Tel: +31 180 445500
Fax: +31 180 445866
Email: general@hma.fki-et.com
Website: www.fki-et.com/hma

## BRUSH SEM s.r.o.

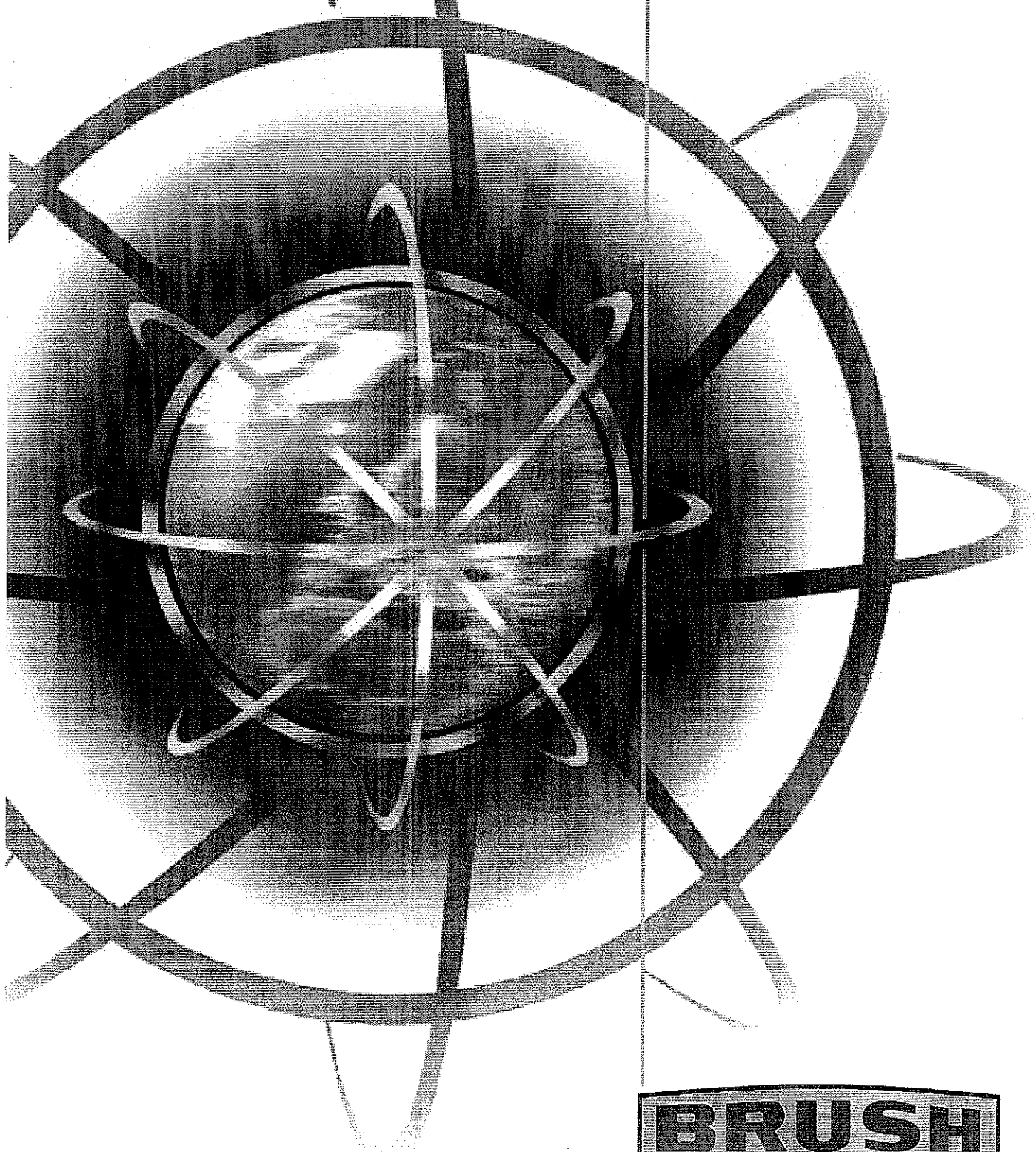
Edvarda Benese 39/564,
301 00 Plzen, Czech Republic
Tel: +420 37 8210111
Fax: +420 37 8210214
Email: sales@sem.fki-et.com
Website: www.fki-et.com/sem


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10/2006

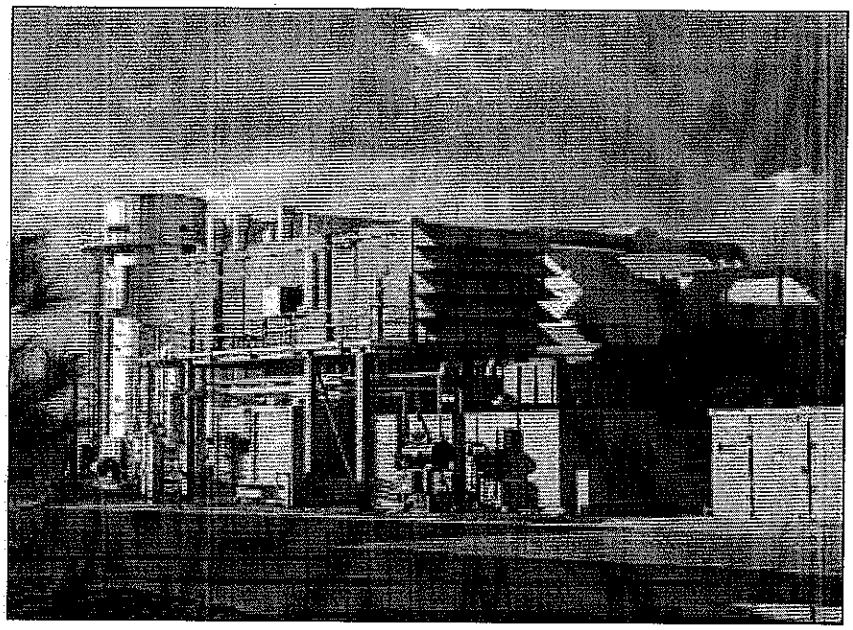
# BRUSH TURBOGENERATORS

# Industrial Power

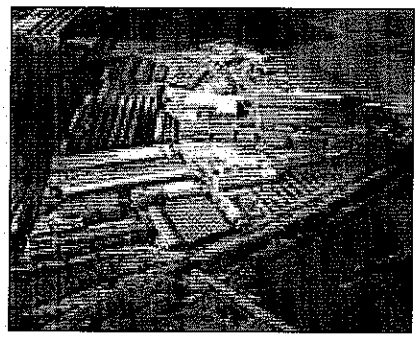


BRUSH

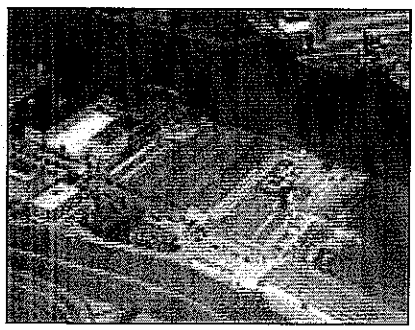
# COMPANY BACKGROUND



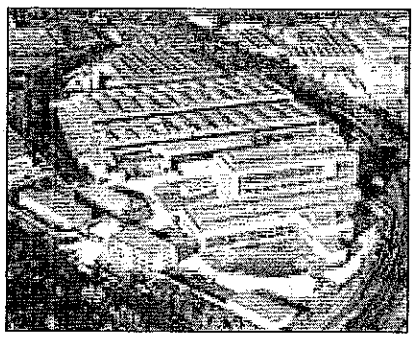
Right: One of four 60MW gas turbine driven BRUSH turbogenerators at a cogeneration installation in the USA.



BRUSH Electrical Machines, Loughborough, England



BRUSH HMA, Ridderkerk, Netherlands



BRUSH SEM, Plzen, Czech Republic

With activities worldwide, over $2.3 billion of annual sales and more than 13,000 employees, FKI is a significant player in the global energy market.

The BRUSH Turbogenerator Division of FKI Energy Technology combines the resources of three of the world's major manufacturers of generators for gas turbine, steam turbine and hydro turbine drive.

BRUSH Electrical Machines Ltd is located at Loughborough in the UK and is designated as FKI Energy Technology's Centre of Excellence for the design and manufacture of power management systems and air cooled 2-pole turbogenerators up to 150MVA.

BRUSH HMA bv, located at Ridderkerk in the Netherlands, is the designated Centre of Excellence for 4-pole generators with ratings between 10MVA and 65MVA.

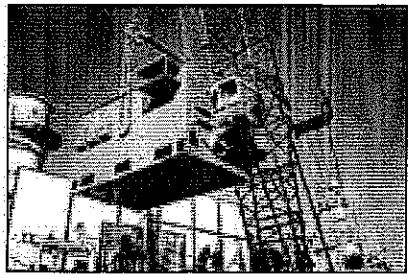
BRUSH SEM sro, located at Plzen in the Czech Republic, is the designated Centre of Excellence for air cooled 2-pole turbogenerators above 150MVA, hydrogen cooled generators and hydrogen/water cooled generators up to 1100MVA and the refurbishment of hydro generators up to 355MVA.

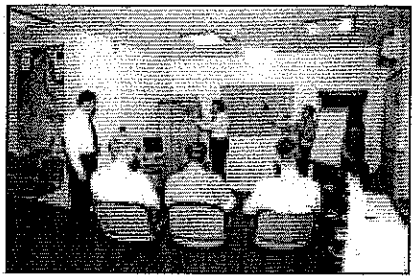
The three companies have a combined total of over 300 years' experience in the design and manufacture of electrical equipment for industrial, marine and offshore applications, backed by modern research and development facilities.

The BRUSH Turbogenerator Division provides a complete electrical service to all sectors of the energy industry. From a product portfolio encompassing generators for base load or intermittent duty, power management systems and fully co-ordinated packages of electrical equipment, BRUSH Turbogenerators can provide equipment and services to meet the most demanding specifications.

All equipment complies with the relevant European, American and International standard specifications. In addition, all three companies are registered to ISO9001:2000, which governs the quality of design, manufacture and service. The requirements needed to obtain and maintain this registration have become a cornerstone of management philosophy.

# AFTER SALES SERVICE & TRAINING





## WORLDWIDE SERVICES PROVIDED BY BRUSH

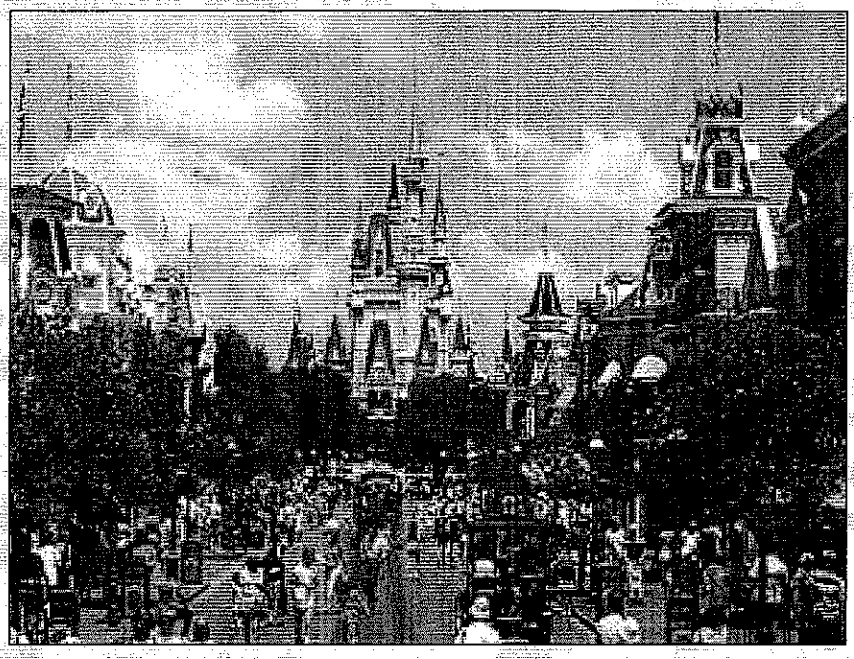
- Supervision of installation
- Commissioning
- Cleaning and inspection
- Rewinds
- Overhaul and refurbishment
- Power management upgrades
- Spare parts
- Repair of any type of rotating electrical machine
- Re-engineering

## FULLY DOCUMENTED TRAINING COURSES PROVIDED BY BRUSH

- PRISMIC power systems
- BRUSH AVR equipment
- Mechanical inspections
- Operator courses
- Maintenance courses
- Protection systems

BRUSH

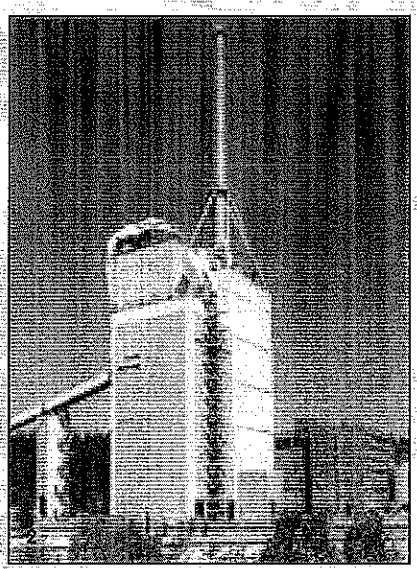
# COMBINED HEAT AND POWER/COGENERATION

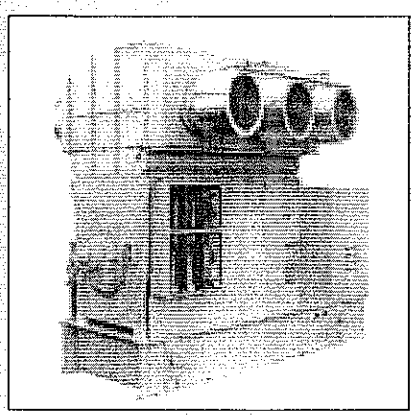


1. Walt Disney World, Orlando, Florida, USA, where a gas turbine, driving a BRUSH generator, is contributing 35MW of electrical power, along with steam for space heating and air conditioning absorption chillers, to the enormous energy demand of the 28000 acre site. © *The Walt Disney Company.*

2. Lahden Lämpövoima Oy's Kymijärvi Power Station in Finland, where a Frame 6 gas turbine driven 40MW BRUSH 2-pole generator contributes to electricity and district heating requirements for the town of Lahti.

3. BRUSH 4-pole turbogenerator for the EPC Abener bioethanol plant in La Coruna, Spain.





A combined heat & power (CHP) scheme offers a high efficiency method for the production of both electrical and thermal energy from a single fuel source, with relatively low installation and operating costs. Electrical power is produced by a generator driven by a gas turbine or reciprocating engine, with the prime mover exhaust heat being recovered as steam for a variety of uses, from process heat to district heating for a whole community.

The USA, the world leader in cogeneration, has hundreds of BRUSH generators operating in CHP schemes. Typical of these is the Downtown Government Centre, Dade County, Florida, where a Rolls Royce SK30 gas turbine and a Peter Brotherhood steam turbine, installed in 1985 and both driving BRUSH generators, produce 27.5MW of electrical power. The plant also produces chilled water for air conditioning and 300 gallons per minute of hot water at an overall thermal efficiency in excess of 75%.

For over 15 years, the Central Birmingham Health Authority has been operating a Centrax gas turbine, driving a 3.6MW BRUSH generator, as part of a CHP scheme at the Queen Elizabeth Hospital in Birmingham, UK. In addition to the 3.6MWe of electricity, the plant, the first of its type at a UK hospital, also provides 5.9MWth of steam for space heating and hot water. A further 1.7MWth of heat is recovered through an economiser to preheat boiler feedwater.

EPC Abener installed new generation equipment for a bioethanol galicia cogeneration plant in La Coruna, Spain, for which Rolls Royce Power Engineering supplied an RB211-6562 turbine driving a BRUSH 4-pole turbogenerator. The La Coruna plant produces 126,000m$^3$ per day of bioethanol, a fuel obtained by processing and distilling fermented biomass. The bioethanol is used as an additive to petrol and diesel oil for use in combustion engines, where it offers the advantages of increased output and improved efficiency. As a renewable energy source, bioethanol contributes to the environment by reducing the use of fossil fuel. The generator was built in 2000 and installation and commissioning were completed by the summer of 2001.

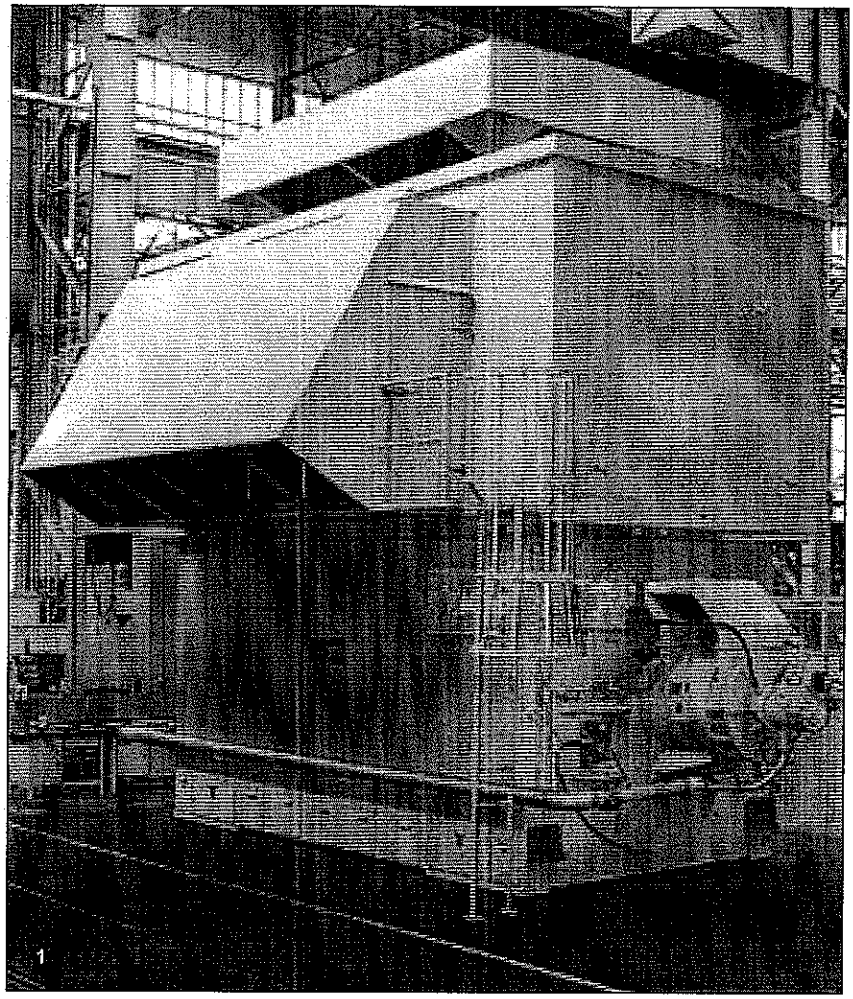
# INDUSTRIAL EXPERTISE

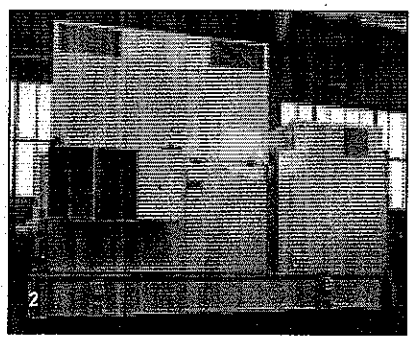
1. BRUSH BDAX 98-330ER 2-pole turbogenerator developed specially for the General Electric LMS 100 aeroderivative gas turbine.

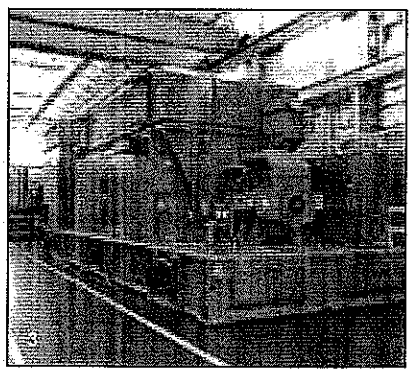
2. Open air cooled BRUSH 4-pole turbogenerator package for gear driven gas turbine drive.

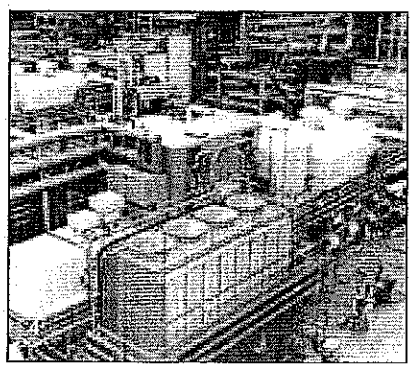
3. One of three gas turbine driven CACW (TEWAC) 40MW BRUSH 2-pole turbogenerators supplied to an oil refinery in Thailand.

4. One of eight 147MW BRUSH 2-pole turbogenerators and auxillary packages installed at Teesside Power Station, UK.



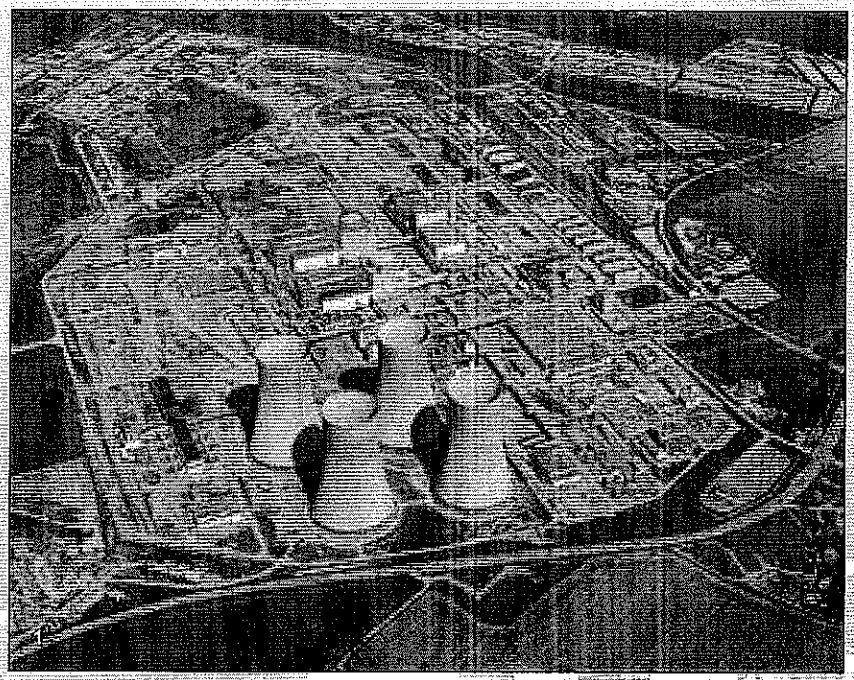

The BRUSH Turbogenerator Division can provide a proven solution for electrical equipment packages selected from the following:

- Air cooled 2-pole turbogenerators up to 300MVA for gas turbine and steam turbine drive.
- Hydrogen and hydrogen/water cooled 2-pole turbogenerators up to 1100MVA for gas turbine and steam turbine drive.
- Salient pole 4-pole turbogenerators up to 65MVA for gas turbine and steam turbine drive.
- Power management and excitation control equipment.
- Comprehensive "round the clock" service capability, including full refurbishment of salient pole multipole generators up to 355MVA for hydro turbine drive and the repair of any make of electrical machine.

Other companies within FKI Energy Technology complete an electrical project capability by providing:

- HV and LV switchboards.
- Transformers.
- Motors.

# UTILITIES AND INDEPENDANT POWER PRODUCERS



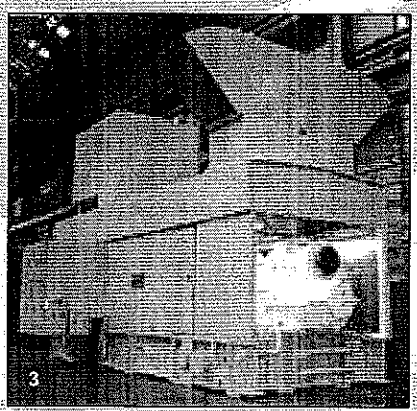
1. Temelin Power Station, Czech Republic, where two BRUSH combined cooled 2-pole turbogenerators have been producing 2000MW of base load electricity since 2002.

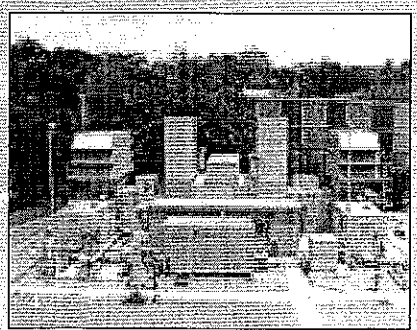
2. Parkeston Power Station, Western Australia, comprising three IHI LM6000 gas turbines driving BRUSH generators.

3. One of five BRUSH 2-pole turbogenerators at Enemalta Corporation's Delimara Power Station, Malta.

4. Pratt & Whitney Power Systems 50MW FT8 "Twin Pac", incorporating a double end drive BRUSH 2-pole generator, at La Dorada, Columbia.



Since providing two 3000kW steam turbine driven generators to the Midland Electricity Corporation in 1912, and heralding the birth of municipal power generation, BRUSH has become a major supplier to utilities and independent power producers the world over.

From the USA to New Zealand, BRUSH gas turbine and steam turbine driven DAX 2-pole and DG 4-pole turbogenerators are being operated on base load and peak load duty and also as synchronous compensators.

For large scale thermal and nuclear power generation, BRUSH has supplied almost 200 high output 2-pole turbogenerators using hydrogen and combined hydrogen-water cooling systems. These generators are designed to be driven by both gas and steam turbines, the design and characteristics being the result of an in-depth knowledge, gained from BRUSH's extensive experience, and the latest design techniques, backed by modern manufacturing methods and plant.

Above 300MVA, hydrogen and combined cooled generators give the advantages of:

- Reduced weight of components.
- More economical operation, in particular under partial load conditions.
- Improved efficiency as a result of significantly reduced ventilation losses.
- Extended insulation life.

Combined cooled machines are available up to 1100MVA.

In 1996, two BRUSH DG 4-pole generators, driven by Frame 5 gas turbines, were commissioned for standby operation at Guernsey Power Station in the UK. Since then, BRUSH has supplied over 150 4-pole generators for a variety of applications, including LM2500, LM2500+, LM6000, Frame 6, RB211 and H25 gas turbines.

1. 10.7MW BRUSH generator at Norsk Hydro's fertilizer plant in Immingham, UK.

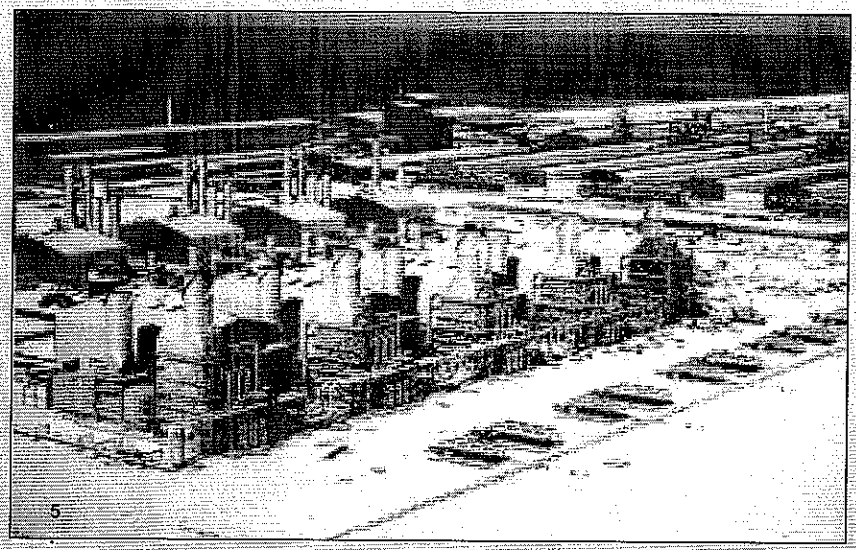
2. A BRUSH generator installed at ICI's No.4 Nitric Acid Plant in the UK.

3. 2.1MW steam turbine driven BRUSH generator at a chemical plant in the UK.

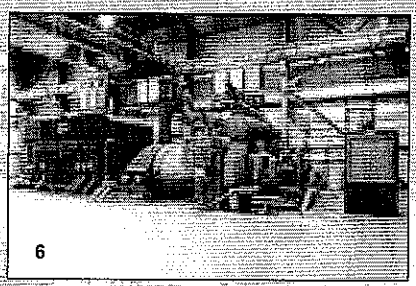
4. Purfleet Board Mill, Essex, UK, generates all the electricity needed for process from a 3.5MW gas turbine and a 7.7MW steam turbine, both driving BRUSH generators.

5. Dubal Aluminium Smelter, Dubai, where 13 gas turbine driven BRUSH 2-pole generators provide over 600MW of electricity for the smelting process.

6. Steam turbine driven, 36MW BRUSH 2-pole generator at a paper mill in Arkansas, USA.



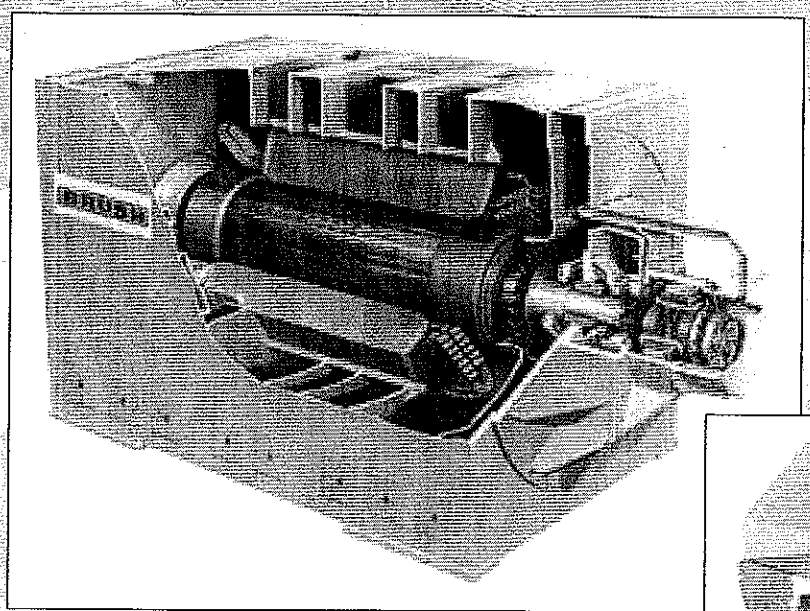
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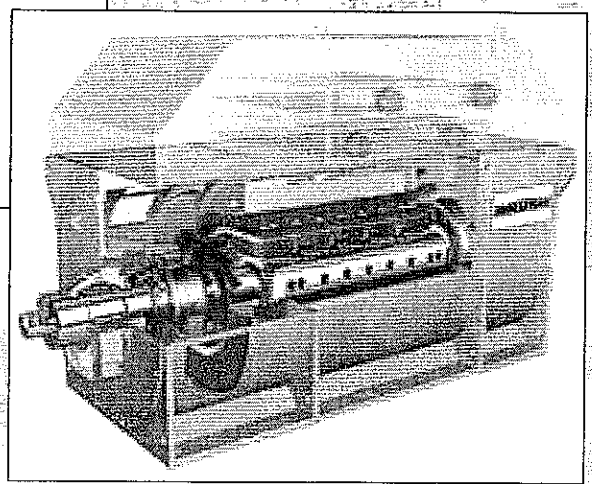


6

Some processes, particularly in chemical industries, require a fluctuating thermal energy input, which inevitably leads to energy waste during periods of low demand.

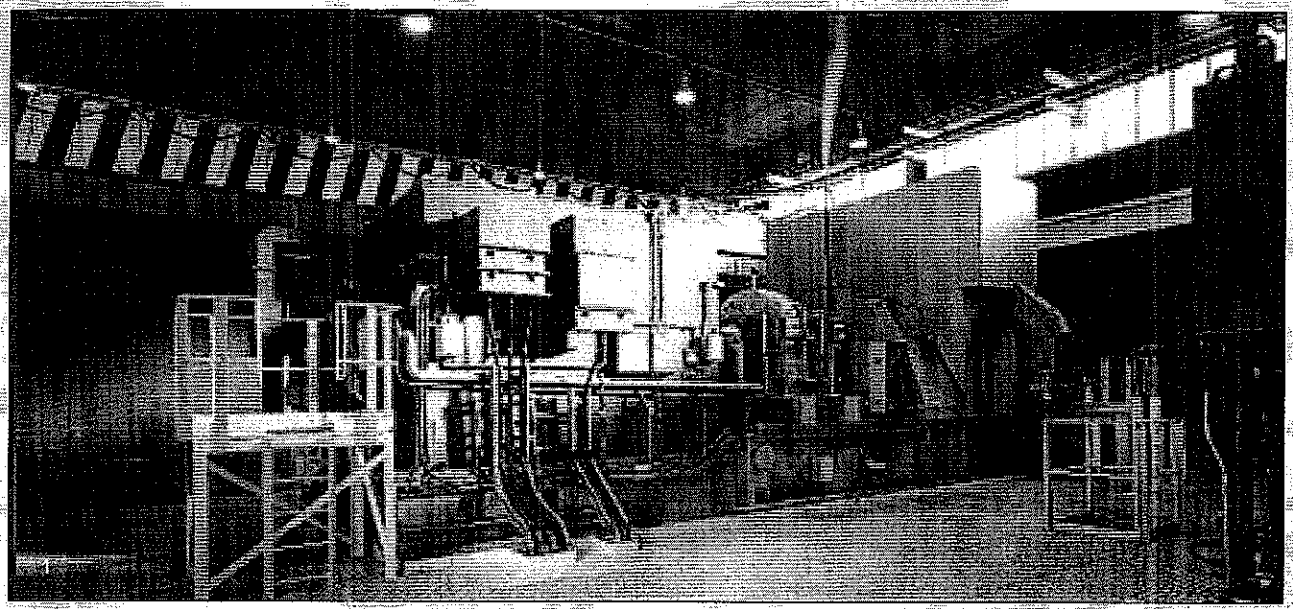
As part of the refurbishment of their No 4 Nitric Acid Plant at Billingham in the UK, ICI installed a 30MW BRUSH generator in a new production train. By designing the train to operate at constant speed, up to 23MW of electrical energy is recovered during the acid production process.

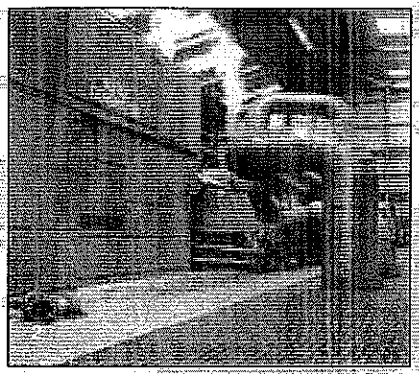




Cutaway views of a BRUSH 2-pole DAX turbogenerator (above) and a BRUSH 4-pole DG turbogenerator (right).

# PROCESS INDUSTRIES

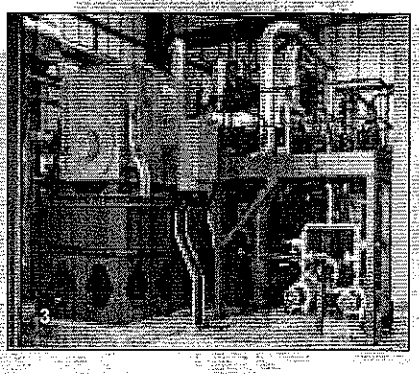




All over the world, BRUSH synchronous generators are supplying essential power to industry.

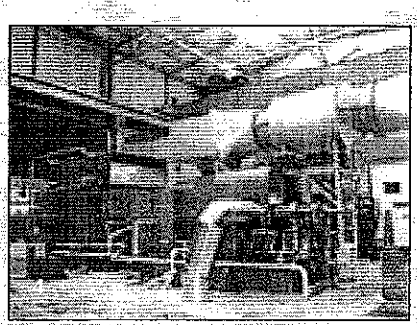
In 1990, a 16MW BRUSH 4-pole generator, manufactured in the Ridderkerk factory, was incorporated into the world's first LM1600 gas turbine package at Hoogovens Steel's Ijmuiden plant in the Netherlands. Since then, BRUSH has established a position as the foremost supplier of generators for the LM1600 gas turbine, in industrial, marine and offshore applications.

In 1997, three BRUSH 4-pole generators were ordered by Thomassen International for the Egyptian oil company Bapetco. Each unit was coupled to a General Electric Frame 5 gas turbine rated at 24.5MVA. As the generators are open air cooled and located outside in a desert environment, special attention had to be paid to the cooling air intake. A self-cleaning "pulse clean" filter removes airborne sand particles and allows the generators to operate for extended periods between filter element changes.



On the other side of the world, Chevron, America's largest producer of California reformulated gasoline, has depended on BRUSH power since 1986, when two General Electric Frame 6 gas turbines, driving BRUSH 2-pole generators, were installed at the El Segundo Refinery in Los Angeles, California, USA.

In 1995, the power generation capability of the refinery was extended from 80MW to 130MW, with the addition of a further Frame 6 gas turbine and a 10MW General Electric steam turbine. Again, BRUSH was chosen to provide the generators, both of which were designed to keep the total fault contribution within the limits of the existing distribution system.



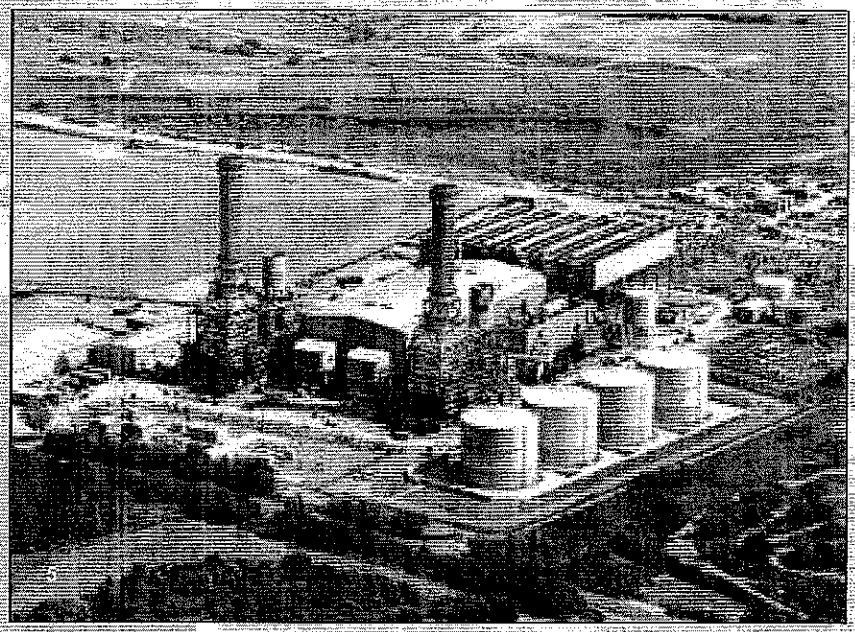
Many industrial processes involve exothermic reactions, from which the heat produced can be harnessed to produce electricity. One such installation is at Norsk Hydro's fertiliser plant at Immingham in the UK, where BRUSH provided two steam turbine driven generators, rated at 10.7MW and 6.1MW, as part of a combined heat and power scheme designed to protect essential supplies to the manufacturing process. To keep within the limitations of the existing distribution system, the generators were designed to have a total combined fault contribution of only 90MVA.

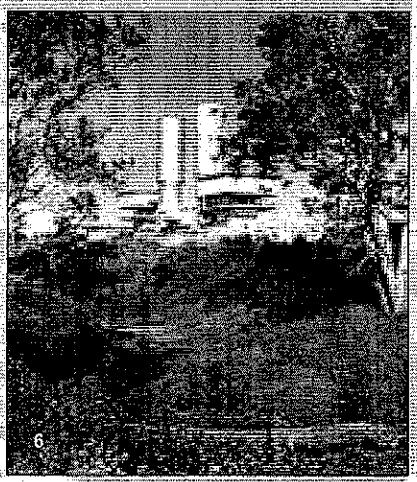
5. Corby Power Station, East Midlands, UK.

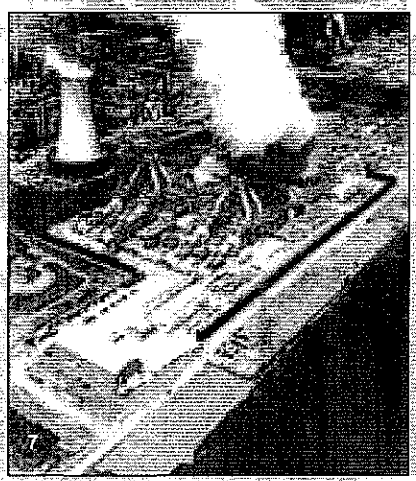
6. Mackay Power Station, Queensland, Australia, where two Rolls-Royce gas turbines drive a 40MW double end drive BRUSH 2-pole generator.

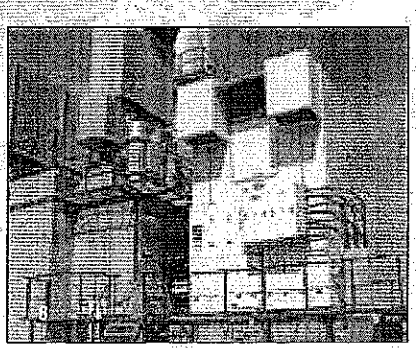
7. Teesside Power Project, UK. At the heart of the power station are eight Siemens Westinghouse W701 gas turbines, each driving a 147MW BRUSH turbogenerator.

8. Gas turbine driven 38MW BRUSH 4-pole generator at a power station in Greece.









Privatisation of the electricity supply industry in the UK gave rise to the now famous "dash for gas", in which old, inefficient thermal power stations were replaced by high efficiency, gas turbine based stations. A 350MW combined cycle power station, built in 1992 at Corby in the East Midlands, was the first large scale combined cycle power station venture to be undertaken by one of the UK regional electricity companies. Power is provided by two Frame 9E gas turbines and a 115MW steam turbine, each driving a BRUSH DAX generator. BRUSH generators, operated by regional electricity companies and independent power producers, are now providing over 2000MW of base load power to the UK distribution system.

In 1995, three DAX turbogenerators were supplied to Parkeston Power Station, Kalgoorlie, Western Australia, as part of the Goldfields Power Project, a joint venture between TransAlta Energy of Canada and Normandy Power Pty Ltd, a wholly owned subsidiary of Gold Mines of Kalgoorlie Ltd. The generators were ordered by Ishikawajima-Harima Heavy Industries Co Ltd (IHI) of Japan, for LM6000 aero derivative gas turbine drive. The units went into service in early 1996, operating on natural gas from the Goldfields Gas Transmission Pipeline.

Aero derivative gas turbines have proved very popular for medium sized power stations. BRUSH is a principal supplier to Pratt & Whitney Power Systems of Windsor, Connecticut, USA, who package the Pratt & Whitney FT8 gas turbine. Recent installations include 50MW double end drive "Twin Pacs" in the USA, South America, China, Ireland and New Zealand, bringing to over 350 the number of Pratt & Whitney engines in various "Twin Pac" arrangements.

BRUSH was selected to provide four 500MW turbogenerators for the ShenTou bituminous coal-fired power station in the Chinese province of Shan-Xi. The first unit entered service in 1992 and the second in 1993. A contract for the supply of two additional units was signed in 1999, these units will be commissioned into service in 2005.

The two largest turbogenerators produced by BRUSH were supplied to the Temelin nuclear power station in the Czech Republic and are rated at 1100MVA. The first generator was produced in 1993 and the second in 1996. The first generator was commissioned into service in 2000 and the second two years later in 2002.

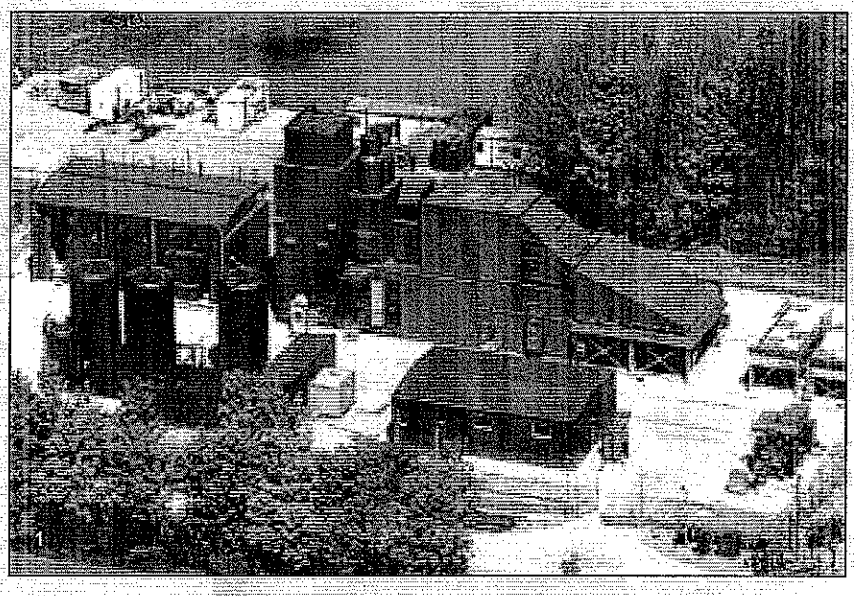
# COMBINED CYCLE GAS TURBINE POWER GENERATION

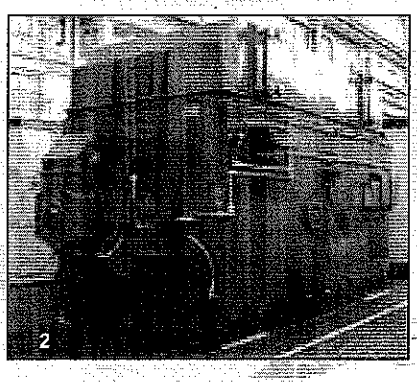
1. Burghfield Power Station, UK, incorporating an LM6000 gas turbine driving a BRUSH 2-pole generator

2. BRUSH 2-pole 50MW generator for gas turbine drive.

3. BRUSH 4-pole 13MW steam turbine generator at Horsens Power Station, Denmark.

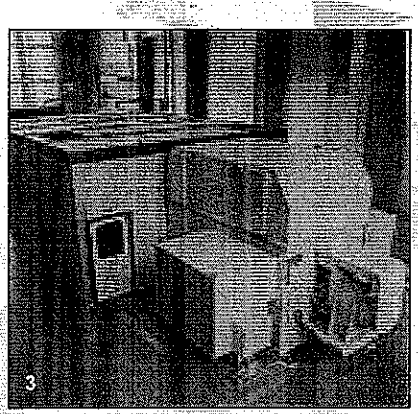
4. Generator capability chart displayed on the operator's VDU of the BRUSH PRISMIC power management system.


1


2

In December 1991, a BRUSH 2-pole turbogenerator left the company's factory at Loughborough for incorporation into the world's first LM6000 gas turbine generation package. This was followed by a further two units in early 1992. Subsequently, BRUSH has built over 300 generators for LM6000 gas turbine drive.

The first three generators were built into pre-assembled and fully factory tested gas turbine/generator packages by Stewart & Stevenson (now GE Aero Energy Products) of Houston, USA. Delivered to Canada, the units are based at two sites, both of which are owned and operated by TransAlta Resources Corporation, a subsidiary of TransAlta Utilities Corporation, one of Canada's largest developers of electric power projects.


3

The first of these plants, at the Ottawa Health Science Centre in Ontario, consists of one LM6000 gas turbine generator set running on natural gas and producing 42MW of electricity. The other two LM6000 units are installed at Boeing's facility in Mississauga, also in Ontario. At each plant, the gas turbine waste heat is recovered to produce an additional 32MW of electricity through an ABB steam turbine driving a BRUSH 2-pole generator.

In early 1997, the Godovari Gas Power Project, at Kakinada, India, became fully operational. The power station, which was built by consortium partners Rolls-Royce/Parsons and Westinghouse Power Generation, was the first independent power project in India to enter commercial operation. The installation comprises three Siemens Westinghouse W251 gas turbines, driving BRUSH 2-pole generators, operating in combined cycle with a 70MW steam turbine.


4

BRUSH's involvement in Indian independent power projects has continued with the installation in 2004 of two 100MW steam turbine driven generators, one at Indal's Hirakud Works in Sambalpur and one at the Jindal Thermal Power Company's South West Power Plant at Tornagallu.

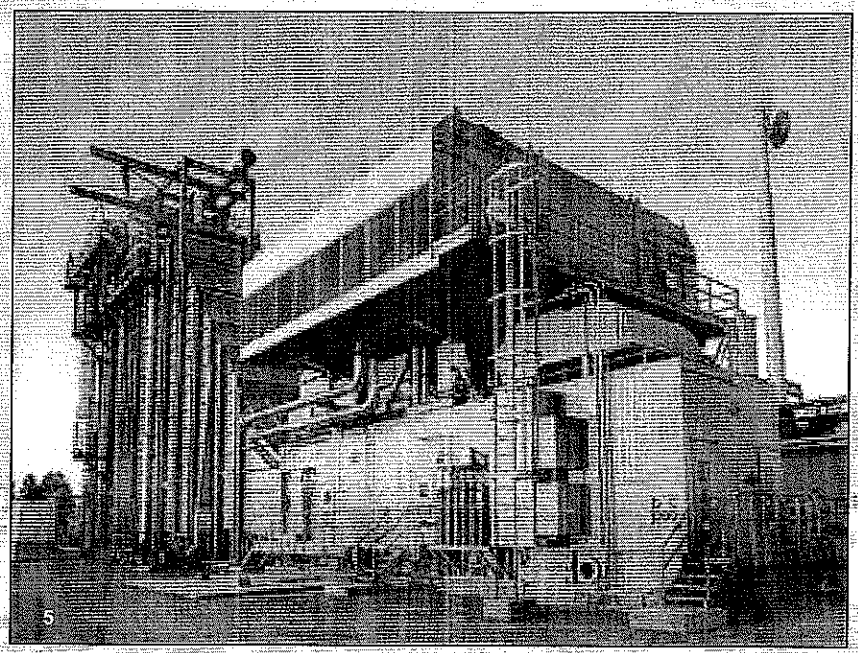
The selection of BRUSH generators for these prestigious installations is not surprising. Since positioning itself as a major supplier to the gas turbine industry in the 1960s, the company has achieved a leading position in the power generation market, as a supplier of both equipment and project engineering expertise.

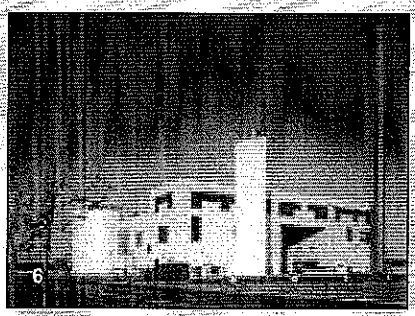
5. One of two LM6000 gas turbine sets, equipped with BRUSH 2-pole generators, at a gas-fired, combined cycle power station in the USA. The plant is equipped with two LM6000s and provides 100 MW of power to the local grid.

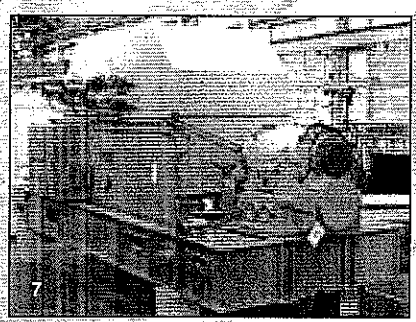
6. Horsens Power Station, Denmark provides 35MW of electricity to the local grid. Power is generated by an LM2500 gas turbine and a 13MW steam turbine in combined cycle, both driving BRUSH generators.

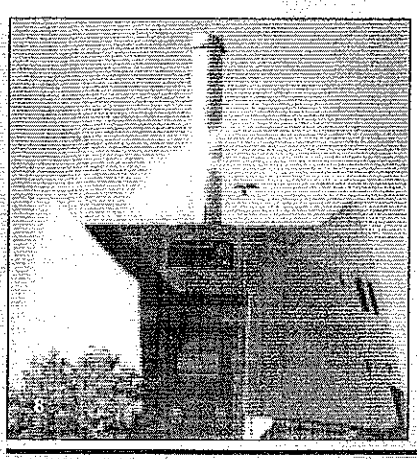
7. A BRUSH 2-pole generator for a Frame 6B gas turbine package.

8. A 57MW gas-fired combined cycle power station owned and operated by the Viborg Municipality, Denmark, supplies base load power to regional electricity distributor Midkraft and process steam to a district heating scheme for 10,000 businesses and homes. The power station comprises a BRUSH generator driven by a 41MW gas turbine at one end and a 16MW steam turbine at the other.









BRUSH was the principal subcontractor in the UK's first large scale commercial venture to produce electricity from landfill gas, at Packington Estate Enterprises Ltd (PEEL) near Birmingham.

The first stage of the project, a simple cycle installation based on a Centrax 501-KB5 gas turbine package, became operational in November 1987. BRUSH supplied the 4800kW generator, 11000 volt switchboard, 1000kVA step down transformer, generator control panel, 415 volt motor control centre, station battery, complete with charger unit, generator neutral earthing resistor and supervision of the electrical power system cabling. In 1992, with a continuing increase in waste gas, a decision was made to convert the installation to combined cycle, with an initial rating of 9000kW. To allow for the future installation of another gas turbine, an 8000kW Peter Brotherhood steam turbine, driving a BRUSH 4-pole generator, was selected.

**Generator Packages**

BRUSH 2-pole and 4-pole turbogenerators are designed for both steam turbine and gas turbine drive, but the extent of the Company's experience is best demonstrated by reference to the gas turbine market. BRUSH has more experience of the use of gas turbines in power generation than any other generator manufacturer in the world. The continued success in the field of gas turbine generation can be attributed to BRUSH's ability to meet the demanding interface requirements of the turbine manufacturers, coupled with competitive prices and keen deliveries.

From the smallest of the DG range, rated at 10MVA, through to 1100MVA combined cooled units, BRUSH has a generator to match all current gas turbine and steam turbine applications.

Where required, BRUSH can provide the generator as a complete package, consisting of a self-supporting baseframe on which are mounted the generator, weatherproof acoustic enclosure, neutral earthing equipment and, where necessary, a load gearbox. The major benefit of a packaged generator is reduced installation and commissioning time at site.

In some drive configurations, either a 2-pole or a 4-pole generator could be used. The choice will depend on the application and possibly on local requirements; each type of generator has merits that may affect the decision. BRUSH is always ready to offer advice on the optimisation of generator selection.

# APPENDIX 9
# CATERPILLAR AND PRATT & WHITNEY
# GAS TURBINE RENTAL UNITS

**From:** Flinn, Dan [DFlinn@atlcat.ca]
**Sent:** Thursday, November 01, 2007 3:11 PM
**To:** King, Brian
**Subject:** Budget Prices fro the XQ5200

**Attachments:** Ideal Generator Data Sheet units 1-11.pdf; 2007 XQ5200 Drawings and data SoLoNox Dual Fuel.pdf; XQ2000.pdf; 3516-2000kw-600v.pdf

Brian, here's some budget prices for the turbine
All prices below are for one unit, not the full package. These are only budget price as well.

**Turbine (XQ5200)**

Following is a preliminary proposal designed for you to make a quick evaluation of the economics of utilizing Mobile Generation for your project.

Proposal Assumptions

1. 15 MW required @ 13.8kv, 60 hz.
2. Project start date: Spring 2008
3. Project duration is 3 months.
3. Fuel Diesel Fuel
4. Assumed elevation sea level.

Preliminary Proposal

Peterson Power Systems is a solutions provider that can provide any level of service you may require from supply of mobile generation equipment and balance of plant to engineering, setup, commissioning, maintenance and operation. Following is budgetary pricing.

A) Budgetary Summary Project Cost Build-up, US dollars 5.2MW Mobile Gas Turbines (SoLoNox): Model XQ5200.

| | |
|---|---|
| Term | 3 months |
| Rental Rate, 3 month minimum (Capacity Charge) | $105,000/month/unit |
| Fired Hour Charge | $42.00/hour/unit |
| Mobilization & Consumables | $16,000/unit. |
| Setup, Commissioning & test | $106,000/unit |
| Technician/Operator | $2,480/wk. (12 hrs per day on call remainder of day) |
| Decommissioning | $48,500/.unit |

Included
1. Mobilization for shipment
2. Setup, commissioning and test of Gas Turbine 3. Solar commissioning Field Service Engineer 4. Rental of Mobile Generation Equipment 5. Maintenance 6. Tear down and decommissioning at end of rental term

Exclusions (excluded items quoted upon request) 1. Fuel storage tanks, fuel forwarding pumps, filter coalescer, daytank and fuel piping.
2. 15kV distribution cabling
3. Utility transformer 15kV to utility voltage 4. Coordination study 5. Import duties 6. Local Taxes of any kind 7. Property damage, and liability insurance (required) 8. Political Risk Insurance (if required) 9. Engineering of any of the above excluded items.
10. Regulatory approval (Operating Permits) 11. Emissions Source testing 12. Freight
(See attached file: 2007 XQ5200 Drawings and data SoLoNox Dual Fuel.pdf)(See attached file: Ideal Generator Data Sheet units 1-11.pdf)

Terms: REQUEST A FULL PROPOSAL FOR COMPLETE TERMS AND CONDITIONS. PRICES SHOWN ARE NET NO FURTHER DISCOUNTS APPLY.

The above proposal is provided for budgeting purposes only. ACTUAL PRICES MAY VARY BASED ON ACTUAL SITE CONDITIONS, RENTAL TERM, AND SCOPE OF SUPPLY.
All pricing is in Cdn Dollars.

Abbreviated Equipment Description

The Caterpillar Mobile Generation Units offered are all less than three to four years old and feature state of the art emissions controls. The Solar Taurus 60's (XQ5200) can operate on both natural gas and liquid fuels (liquid fuel quoted upon request) such as kerosene and diesel.

All of the Mobile Generation units are self-contained, sound attenuated, trailerized for easy delivery, and designed for quick connection and convenient servicing. All of these packages maintain a high power density. These full utility-grade Mobile Generation Units are capable of running stand-alone or infinitely parallel with the utility. On board are all of the necessary controls, and associated switchgear for parallel operation with a utility source. All of the mobile generation units are designed for minimal aesthetic and sound impact to the area. These sound attenuated enclosures have sound levels of 85 dbA at three feet (3').

Dan Flinn

Coordinator Rental/Used Generators

175 Akerley Blvd
PO Box 953
Dartmouth, NS B2Y 3Z6

Office 902 468 0581
Cell 902 499 6393
Fax 902 468 4222

CAT Rental Power

# XQ5200
# Mobile Power Unit




## Rental Power—When and Where You Need It

The XQ5200 is the answer to your need for short term generating capacity that is both economical and environmentally friendly. Designed as an on-site generating system where low emissions, fast setup and reliable operation are critical, the XQ5200 is based on the proven *Solar*® 5.2 MW *Taurus*™ 60 gas turbine generator set a proven industry standard.

### Easy to Install and Relocate

- Highway Transportable
- Modular Design for Quick Set-up and Connection
- No Concrete Foundation Required
- Compact Footprint to Minimize Space Requirements
- CSA certified

### Environmentally Friendly

- Low Emissions, Utilizing SoLoNOx™ Combustion System
- No Visible Emissions
- Sound Attenuation Package for Quiet Operation
- Low Profile Design to Minimize Installed Height
- Easy to Permit

### Flexible Solution

- Short and Long Term Rental Options Available
- 5.2 MW Output, 12.47 kV to 13.8 kV, 60 Hertz
- Fuel Flexibility, Natural Gas or Diesel

### Complete Systems Solution

- Set-up and Commissioning
- Maintenance Included in Rental
- Operators Available
- Site Preparation Available
- Transformer Options

### Operational Features

- Dispatchable to be On Line in Six Minutes (from cold start)
- Range of Control System Options for Remote Operation
- Utility Grade Switchgear with Programmable Protective Relay Module
- KVAR Control for Excellent Reactive Power Capability

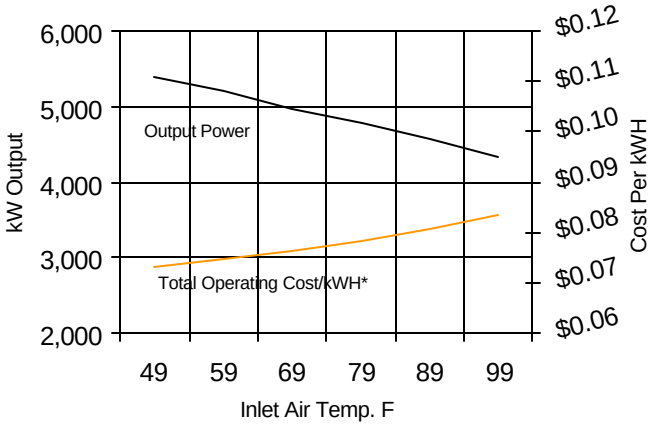
CAT Rental Power

# XQ5200
# Mobile Power Unit

## Nominal Generator Set Performance

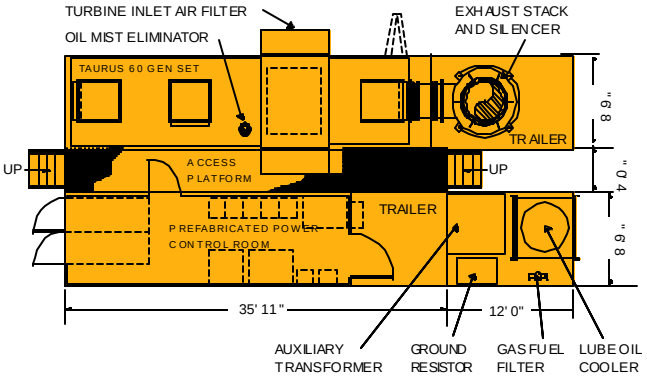
At the core of the XQ5200 is Solar's 5.2 MW *Taurus*™ 60 industrial gas turbine, with a population of more than 1,000 units in the field. The XQ5200 combines the features and benefits of the proven *Taurus*™ 60 industrial gas turbine with a mobile system that is easy to relocate and connect.

| | |
|---|---|
| Output Power, kWe<br>ISO: 15º C (59º F), sea level | 5,200 |
| Heat Rate, (Btu/kWe-hr) | 11,263 |

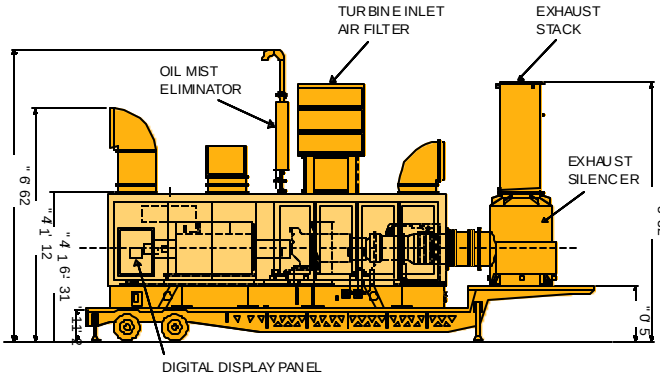



*Total operating cost includes fuel @ $3.50/MMBtu, Rental, Sales Tax and Maintenance

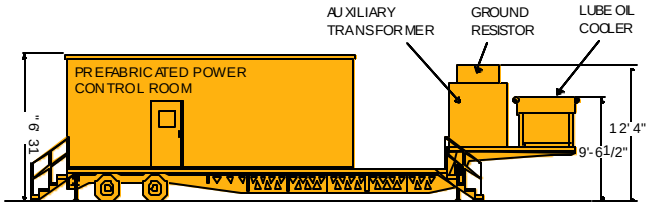
## Typical Dimensions




**Installation Plan View**




**Generator Set Module**




**Power Control Module**

**Mobile Power– When and Where You Need It**



**XQ5200 in Transit**

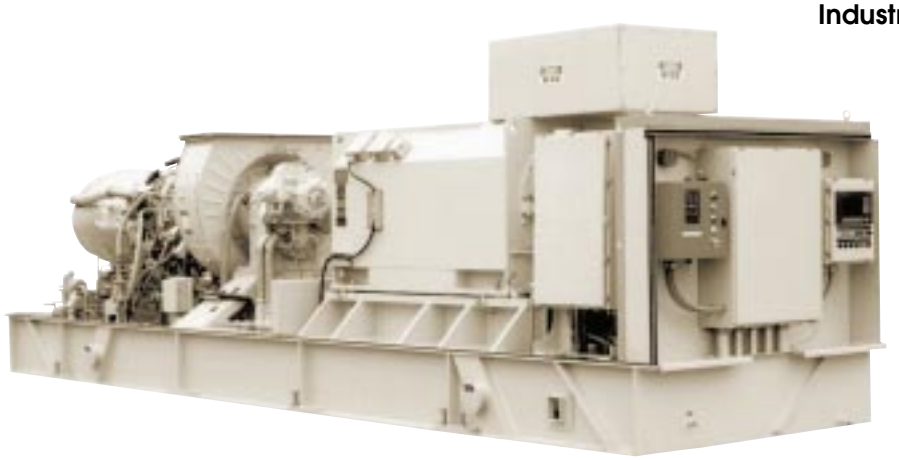
**CATERPILLAR: WHERE THE WORLD TURNS FOR POWER**

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*Solar, Taurus and SoLoNO$_x$* are trademarks of Solar Turbines Incorporated
Specifications subject to change without notice. Printed in U.S.A.

Solar® Turbines
A Caterpillar Company

# TAURUS 60
## Gas Turbine Generator Set

**Industrial/Utility Grade**



## Features

- Industrial Gas Turbine Package
- Compact, Integrated Package Providing Ease of Installation
- Factory Tested
- Dry, Low Emission (*SoLoNOx*™) Combustion Available
- Onskid Microprocessor-Control with Auto Sync Capability
- Multiple Fuel Capability

## Package Arrangement

### Gas Turbine

- *Taurus*™ 60 Industrial, Single-Shaft
- Axial Compressor – 12 Stages
- Annular Combustion Chamber
  - 12 Fuel Injectors
- Coatings
  - Compressor: Inorganic Aluminum
  - Turbine and Nozzle Blades: Precious Metal Diffusion Aluminide
- Proximity Probe Vibration Transducers

### Main Reduction Drive

- Epicyclic
  - 1800 or 1500 rpm
  - Acceleration Vibration Transducers

### Generator

- Salient Pole, 3 Phase, 6 Wire, Wye Connected, Synchronous with Brushless Exciter
- Open Drip-Proof Construction
- Sleeve Bearings
- Velocity Vibration Transducers
- Solid-State Voltage Regulation with Permanent Magnet Generator
- NEMA Class F Insulation with F Rise
- Continuous Duty Rating

### Package

- Steel Base Frame with Drip Pans
- Direct-Drive AC Start System
- Natural Gas Fuel System
- Control System
  - Microprocessor-Based PLC
  - Generator Control
  - Vibration and Temperature Monitoring
  - Auto Synchronizing
- Integrated Lube Oil System
  - Turbine-Driven Lube Pump
  - AC Pre/Post Lube Pump
  - Backup Lube Pump
  - Air/Oil Cooler
  - Integral Lube Oil Tank
  - Lube Oil Tank Heater
  - Lube Oil Filter
- Documentation
  - Drawings
  - Quality Control Data Book
  - Inspection and Test Plan
  - Test Reports
  - O&M Manuals
- Factory Testing of Turbine and Package

### Optional Equipment/Services

- Generator Options:
  - WPII, TEWAC
  - Standby Duty Rating
  - Standard Voltages: 3300, 6600, 11,000 50 Hz; 4160, 6900, 12,470, 13,800 60 Hz
- Fuel Systems
  - Liquid
  - Dual (Gas/Liquid)
  - *SoLoNOx*, Dry, Low Emission
  - Alternate Fuels (such as naphtha, propane, low Btu)
- Lube Oil System
  - Water/Oil Lube Cooler
  - Electrostatic Demister
  - Duplex Lube Oil Filters
- Control System
  - Remote Display/Control Terminal
  - Heat Recovery Application Interface
  - Serial Link Supervisory Interface
  - KW Control
  - KVAR/Power Factor Control
  - Turbine Performance Map
  - Historical Displays
  - Printer/Logger
  - Predictive Emissions Monitoring
  - Field Programming Terminal
- Accessory Equipment
  - 24-VDC Battery/Charger System
  - Turbine Cleaning System: On-Crank and On-line
  - Package Lifting Kit
- Weatherproof Acoustic Enclosure
- Ancillary Equipment: Various Air Inlet and Exhaust Systems
  - Inlet and Exhaust Silencers
  - Self-Cleaning or Prefilter/Barrier Air Inlet Filter
  - Inlet Evaporative Cooler
  - Inlet Chiller Coils
  - Ancillary Support Frame

Solar® Turbines
A Caterpillar Company

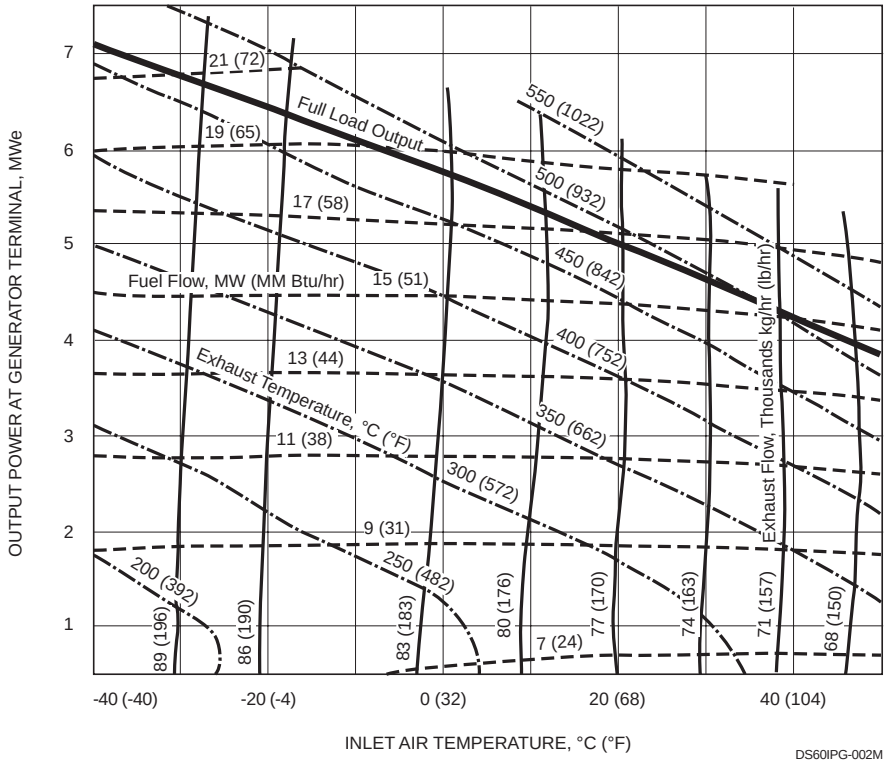
# TAURUS 60
## Gas Turbine Generator Set

## Nominal Performance*

| | |
|---|---|
| Output Power, kWe<br>ISO: 15°C (59°F), sea level | 5200 |
| Heat Rate, kJ/kWe-hr<br>(Btu/kWe-hr) | 11 882<br>(11,263) |
| Exhaust Flow, kg/hr<br>(lb/hr) | 79 284<br>(174,798) |
| Exhaust Temperature, °C<br>(°F) | 486<br>(906) |

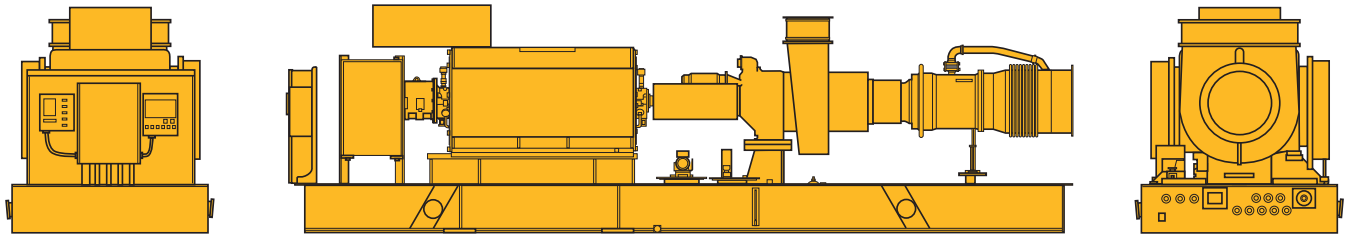
** No inlet or exhaust losses*
*Relative humidity 60%*
*Natural gas fuel with*
*LHV = 31.5 to 43.3 MJ/nm³*
*(800 to 1100 Btu/scf)*

### Available Performance




DS60IPG-002M

## Typical Service Connections



Forward End — Left Side — Aft End

DS60IPG-003M

### Forward End
- Turbine Control Box

| | |
|---|---|
| Length: | 9754 mm (32’ 0”) |
| Width: | 2438 mm (8’ 0”) |
| Height: | 2591 mm (8’ 6”) |
| Approx. Weight: | 29 300 kg (64,590 lb) |

### Left Side
- Lube Oil: Drain, Vent, Cooler
- Generator Control Box, Power
- Generator Drip Pan Drain
- AC Power
  - Lube Tank Heater
  - Pre/Post Lube Pump
  - Backup Lube Pump

### Right Side
- AC Power - Start Motor
- Generator Monitor Box

### Aft End
- Fuel Inlet
- Turbine Cleaning
- Fuel Filter, Combustor and Exhaust Collector Drains
- Auxiliary Air (optional) for:
  - Liquid Fuel Atomizing
  - Self-Cleaning Filter
- AC Power
  - Liquid Fuel Pump (optional)
- Package Ground

Solar Turbines Incorporated

**FOR MORE INFORMATION**

ISO-9001
DNV
CERTIFICATED FIRM

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DS60IPG/1198/5M






# XQ5200 Data Sheet
# SoLoNox, Dual Fuel
# 60 Hz.

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**Table 1. XQ5200 Designation**

| | |
|---|---|
| ***Manufacturer*** | Solar Turbines Inc. |
| ***Turbine Model*** | Taurus 60, T7300S |
| ***Package Model Designation*** | XQ5200 |
| ***Combustion System*** | So Lo Nox™ |
| ***Fuel*** | Natural Gas & Diesel #2 |

**Table 2. Dual Fuel Performance Data ISO***, XQ5200 Mobile Power Unit

| | ***Natural Gas*** | ***Natural Gas*** | ***Diesel #2*** | ***Diesel #2*** |
|---|---|---|---|---|
| | ***English*** | ***Metric*** | ***English*** | ***Metric*** |
| ***Power Output*** | 5,200 kWe | 5,200 kWe | 5,089 kWe | 5,089 kWe |
| ***Heat Rate(LHV)*** | 11,263 Btu/kWe-hr | 11,900 kJ/kWe-hr | 11,376 Btu/kWe-hr | 12,002 kJ/kWe-hr |
| ***Fuel Flow (LHV)*** | 58.6 mmBTU/hr | 61.8 mmkJ/hr | 57.9 mmBTU/hr | 61.0 mmkJ/hr |
| ***Emissions** NOX*** | 48 PPMvd | 48 PPMvd | 96 PPMvd | 96 PPMvd |
| | 11.16 LBM/HR | 5.06 kg/hr | 22.41 LBM/HR | 10.16 kg/hr |
| ***CO*** | 50 PPMvd | 50 PPMvd | 50 PPMvd | 50 PPMvd |
| | 7.1 LBM/HR | 3.22 kg/hr | 7.1 LBM/HR | 3.22 kg/hr |
| ***Gen. Voltage @ 60 hz.*** | 12.47 to 13.8 KV | 12.47 to 13.8 KV | 12.47 to 13.8 KV | 12.47 to 13.8 KV |
| ***Voltage Steady State*** | 0.5% | 0.5% | 0.5% | 0.5% |
| ***Short Circuit*** | 300% for 10 sec. | 300% for 10 sec. | 300% for 10 sec. | 300% for 10 sec. |

* ISO = Sea Level, 60% Relative Humidity, No inlet or exhaust losses.
** Emissions valid if Load factor is > 50% on natural gas and > 80% on diesel fuel.

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## Table 3. Natural Gas Site Performance data, METRIC

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **TAURUS 60-T7300S** | | | **Heat Rate Data Given is Lower Heating Value** | | | | |
| **GSC STANDARD** | | | | | | | |
| **Std. Natural Gas Fuel** | | | | | | | |
| **Rel Humid, %** | 60 | | | | | | |
| **SITE ELEVATION:** | 0 | metre | | | | | |
| **BAROMETRIC PRESSURE:** | 760.0 | mmHg | | | | | |
| **INLET DUCT LOSS:** | 76.2 | mmH2O | | | | | |
| **EXHAUST DUCT LOSS:** | 76.2 | mmH2O | | | | | |
| **Nominal Data Single Unit** | | | | | | | |
| AMBIENT AIR TEMPERATURE (T1): | -7 | 4 | 15 | 27 | 38 | 48 | °C |
| PART POWER ( kWe), % LOAD, or 0 for MAX: | 100% | 100% | 100% | 100% | 100% | 100% | kWe |
| Nominal OUTPUT POWER: (@terminals) | 5,869 | 5,488 | 5,095 | 4,661 | 4,214 | 3,827 | kWe |
| FUEL FLOW (LHV): | 67,563 | 64,765 | 61,323 | 57,681 | 54,254 | 51,485 | MJ/hr |
| Nominal HEAT RATE: (@terminals) | 11,511 | 11,802 | 12,037 | 12,375 | 12,875 | 13,452 | kJ/kWe-hr |
| EXHAUST GAS TEMPERATURE (T7): | 484 | 485 | 488 | 495 | 504 | 516 | °C |
| EXHAUST GAS FLOW: | 83,982 | 81,689 | 78,819 | 74,939 | 70,718 | 66,866 | kg/hr |
| Nominal THERMAL EFFICIENCY: (@terminals) | 31.28 | 30.51 | 29.92 | 29.10 | 27.97 | 26.77 | % |
| PCD PRESSURE: | 1,202 | 1,159 | 1,110 | 1,061 | 1,002 | 946 | kPaG |
| EXHAUST HEAT (from T7 to T9): | 31,886 | 31,167 | 30,277 | 29,369 | 28,405 | 27,712 | MJ/hr |

## Table 4. Natural Gas Site Performance data, ENGLISH

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **TAURUS 60-T7300S** | | | **Heat Rate Data Given is Lower Heating Value** | | | | |
| **GSC STANDARD** | | | | | | | |
| **Std. Natural Gas Fuel** | | | | | | | |
| **Rel Humid, %** | 60 | | | | | | |
| **SITE ELEVATION:** | 0 | Feet | | | | | |
| **BAROMETRIC PRESSURE:** | 29.9 | "Hg | | | | | |
| **INLET DUCT LOSS:** | 3 | "H2O | | | | | |
| **EXHAUST DUCT LOSS:** | 3 | "H2O | | | | | |
| **Nominal Data Single Unit** | | | | | | | |
| AMBIENT AIR TEMPERATURE (T1): | 20 | 40 | 59 | 80 | 100 | 118 | °F |
| PART POWER ( kWe), % LOAD, or 0 for MAX: | 100% | 100% | 100% | 100% | 100% | 100% | kWe |
| Nominal OUTPUT POWER: (@terminals) | 5,869 | 5,488 | 5,095 | 4,661 | 4,214 | 3,827 | kWe |
| FUEL FLOW (LHV): | 64 | 61 | 58 | 55 | 51 | 49 | mmBTU/hr |
| Nominal HEAT RATE: (@terminals) | 10,911 | 11,186 | 11,409 | 11,729 | 12,203 | 12,750 | BTU/kWe-hr |
| EXHAUST GAS TEMPERATURE (T7): | 903 | 906 | 910 | 923 | 939 | 960 | °F |
| EXHAUST GAS FLOW: | 185,149 | 180,094 | 173,767 | 165,212 | 155,908 | 147,414 | lb/hr |
| Nominal THERMAL EFFICIENCY: (@terminals) | 31.28 | 30.51 | 29.92 | 29.10 | 27.97 | 26.77 | % |
| PCD PRESSURE: | 174 | 168 | 161 | 154 | 145 | 137 | PsiG |
| EXHAUST HEAT (from T7 to T9): | 30 | 30 | 29 | 28 | 27 | 26 | mmBTU/hr |

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## Table 5. Diesel #2 Site Performance data, METRIC

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Diesel 2-D Fuel** | | | | | | | |
| **RELATIVE HUMIDITY** | 76 | % | | | | | |
| **SITE ELEVATION:** | 0 | metre | | | | | |
| **BAROMETRIC PRESSURE:** | 760.0 | mmHg | | | | | |
| **INLET DUCT LOSS:** | 76.20 | mmH2O | | | | | |
| **EXHAUST DUCT LOSS:** | 76.20 | mmH2O | | | | | |
| **Distillate Fuel Formulas, (Diesel #2)** | | | | | | | |
| **Heat Value KJ/kg** | 41,925.00 | | | | | | |
| **kg/litre** | 0.8543 | | | | | | |
| **Fuel Temp.** | 29 C | | | | | | |
| AMBIENT AIR TEMPERATURE (T1): | -6.7 | 4.4 | 15.0 | 26.7 | 37.8 | 47.8 | °C |
| PART POWER ( kWe), % LOAD, or 0 for MAX: | 100% | 100% | 100% | 100% | 100% | 100% | kWe |
| Nominal OUTPUT POWER: (@terminals) | 5,750 | 5,377 | 4,990 | 4,565 | 4,118 | 3,738 | kWe |
| Nominal HEAT RATE: (@terminals) | 11,625 | 11,907 | 12,152 | 12,507 | 13,029 | 13,634 | kJ/kWe-hr |
| EXHAUST GAS TEMPERATURE (T7): | 484 | 487 | 489 | 496 | 505 | 518 | °C |
| EXHAUST GAS FLOW: | 84,182 | 81,858 | 78,985 | 75,067 | 70,838 | 66,999 | kg/hr |
| Nominal THERMAL EFFICIENCY: (@terminals) | 30.98 | 30.24 | 29.63 | 28.79 | 27.64 | 26.41 | % |
| PCD PRESSURE: | 1,197 | 1,152 | 1,109 | 1,057 | 999 | 945 | kPaG |
| EXHAUST HEAT (from T7 to T9): | 29,429 | 28,894 | 28,013 | 27,264 | 26,404 | 25,874 | MJ/hr |
| Liters per Hour | 1,866 | 1,788 | 1,693 | 1,594 | 1,498 | 1,423 | Nominal |
| Liters per kW-HR | 0.325 | 0.332 | 0.339 | 0.349 | 0.364 | 0.381 | Nominal |
| Liters per MW-HR | 325 | 332 | 339 | 349 | 364 | 381 | Nominal |

## Table 6. Diesel #2 Site Performance data, ENGLISH

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Diesel 2-D Fuel** | | | | | | | |
| **RELATIVE HUMIDITY** | 60 | % | | | | | |
| **SITE ELEVATION:** | 0 | feet | | | | | |
| **BAROMETRIC PRESSURE:** | 29.9 | "Hg | | | | | |
| **INLET DUCT LOSS:** | 3.00 | "H2O | | | | | |
| **EXHAUST DUCT LOSS:** | 3.00 | "H2O | | | | | |
| **Distillate Fuel Formulas, (Diesel #2)** | | | | | | | |
| **Heat Value, BTU/LB in LHV** | 18,390 | | | | | | |
| **Lbs./Gal.** | 7.001 | | | | | | |
| **Fuel Temp.** | 85 deg. F | | | | | | |
| AMBIENT AIR TEMPERATURE (T1): | 20 | 40 | 59 | 80 | 100 | 118 | °F |
| PART POWER ( kWe), % LOAD, or 0 for MAX: | 100% | 100% | 100% | 100% | 100% | 100% | kWe |
| Nominal OUTPUT POWER: (@terminals) | 5,750 | 5,377 | 4,990 | 4,565 | 4,118 | 3,738 | kWe |
| Nominal HEAT RATE: (@terminals) | 11,018 | 11,286 | 11,518 | 11,854 | 12,350 | 12,923 | BTU/kWe-hr |
| EXHAUST GAS TEMPERATURE (T7): | 903 | 909 | 911 | 926 | 941 | 964 | °F |
| EXHAUST GAS FLOW: | 185,589 | 180,465 | 174,132 | 165,494 | 156,170 | 147,708 | lb/hr |
| Nominal THERMAL EFFICIENCY: (@terminals) | 30.98 | 30.24 | 29.63 | 28.79 | 27.64 | 26.41 | % |
| PCD PRESSURE: | 174 | 167 | 161 | 153 | 145 | 137 | PsiG |
| EXHAUST HEAT (from T7 to T9): | 28 | 27 | 27 | 26 | 25 | 25 | mmBTU/hr |
| Gallons per Hour | 492.1 | 471 | 446 | 420 | 395 | 375 | Nominal |
| Gallons per kW-HR | 0.086 | 0.088 | 0.089 | 0.092 | 0.096 | 0.100 | Nominal |
| Gallons per MW-HR | 85.6 | 87.7 | 89.5 | 92.1 | 95.9 | 100.4 | Nominal |

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**Table 7. Dimensional Data & Weights, Installed** XQ5200 Mobile Power Unit

| | English | Metric |
|---|---|---|
| ***Length*** | 48 ft. | 14.6 meters |
| ***Width*** | 21 ft. | 6.4 meters |
| ***Height*** | 26.6 ft. | 8.1 meters |
| ***Installed Weights*** | | |
| ***Turbine Section*** | 118,000 lbs | 54 M tons |
| ***PCR Trailer*** | 55,000 lbs. | 25 M tons |

**Table 7A. Dimensional Data and Weights, Ocean Shipping.**

| *Item #.* | *Lbs. (Metric tons)* | *Dimensions L X W X H English (Meters)* | *Description* |
|---|---|---|---|
| 1 | 118,000 (53.6) | 48'3" X 9' X 14'2" (14.7 x 2.75 x 4.32) | Turbine Enclosure w/ Integral Trailer. Air ride, 3 Axle, Mfg. by Solar Turbines Inc.. |
| 1A | 6,900 (3.2) | 14'1" X 8'6" X 3'6" (4.3 x 2.6 x 1.1) | Two Axle Air Ride Booster. Connects to Item 1 for highway transport but is removed for ocean transit and when assembled for operation. |
| 2 | 55,000 (25) | 46' X 8' 6" X 13'9.5" (14 X 2.6 X 4.2) | Power Control Room w/ Integral Trailer. Air ride, 2 Axle. Manufactured by Solar Turbines Inc. |
| 3 | 35,000 (15.9) | 40' X 8' X 8' 6" (12.2 x 2.5 x 2.6) | 40 ft. shipping container packed with turbine auxiliary components. |
| 3A | 8,500 (3.9) | 41' x 8' x 4' (12.5 x 2.5 x 1.2) | Chassis for Item 3. Optional 40 ft. fixed chassis for container. |
| 4 | 35,000 (15.9) | 40' X 8' X 8' 6" (12.2 x 2.5 x 2.6) | 40 ft. shipping container packed with special tooling and spare parts |
| 4A | 8,500 (3.9) | 41' x 8' x 4' (12.5 x 2.5 x 1.2) | Chassis for Item 4. Optional 40 ft. fixed chassis for container. |

**Table 7B. Dimensional Data and Weights, Highway Shipping.**

| *Item #.* | *Lbs. (Metric tons)* | *Dimensions L X W X H English (Meters)* | *Description* |
|---|---|---|---|
| 1 & 1A | 124,900 (56.7) | 62'1" x 9' X 14"2" (19 x 2.75 x 4.32) | Turbine Enclosure w/ Integral Trailer & Booster. Item 1 & 1A configured for highway transport by Truck. 5 axles. |
| 2 | 55,000 (25) | 46' X 8' 6" X 13'9.5" (14 X 2.6 X 4.2) | Power Control Room w/ Integral Trailer. Air ride, 2 Axle. Manufactured by Solar Turbines Inc. |
| 3 & 3A | 43,500 (15.9) | 41' X 8' X 12' 6" (12.5 x 2.5 x 3.8) | 40 ft. container w/ Chassis packed with turbine auxiliary components. |
| 4 & 4A | 43,500 (15.9) | 41' X 8' X 12' 6" (12.5 x 2.5 x 3.8) | 40 ft. container w/ Chassis packed with special tooling & spares. |

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**Table 8. Installation Requirements** XQ5200 Mobile Power Unit

| | *English* | *Metric* |
|---|---|---|
| ***Natural Gas*** | | |
| ***Gas Pres.*** | 250 PSIG | 1,723 KPAG |
| ***Max. Gas Demand*** | 1,400 SCFM | 39.6 $M^3$/MIN. |
| ***Diesel #2*** | | |
| ***Fuel Pres.*** | 25 – 50 PSIG | 172 – 345 KPAG |
| ***Fuel Flow*** | 8 GPM | 30.3 L/Min |
| ***Foundation*** | | |
| ***Gravel Compacted to*** | 2,500 lbs./ft.2 | 120 kPA |
| ***Fuel Quality*** | | |
| **Clean dry fuel Per Solar Spec. ES 9-98.** | | |

**Table 9. Infrastructure Requirements,** XQ5200 Mobile Power Unit

| |
|---|
| ***Connections*** |
| **Black Start, if needed (480V 60 hz., 200kW)** |
| **Telephone Line, ether net, broadband connection for Remote Communication & Control** |
| ***Set Up & Commissioning*** |
| **Three – Five days** |
| **Small crane to lift components on roof, & fork Lift.** |

**Table 10. Solar Turbotronic Controller,** XQ5200 Mobile Power Unit

| *Allen Bradley, PLC-5* |
|---|
| Provides sequencing to the package's operating systems during starting, running & shutdown, and provides package monitoring and protection during all phases of operation. Key features include… |
| *****Local operator interface and monitoring. |
| *Interface and monitoring in power control trailer |
| *Remote interface and monitoring. |
| *Operational summary displays of alarms, shutdowns, temperatures, pressures, vibration, engine performance, generator kW, voltage, p.f., hz., amps, current. |
| *Relay backup in event of PLC failure |
| *Flexibility to change logic or add features |

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**Table 11. Switchgear,** XQ5200 Mobile Power Unit

| ***Operating Features, (One Line Available upon request)*** |
|---|
| Parallel operation with the utility. |
| Island operation single or multiple units**.** |
| Protective Relays, (See Table 8) |
| Vacuum Circuit Breakers, 1,200A, 500MVA @ 15 KV |
| Breaker #1 customer load connection |
| Breaker #2 feeds Aux. Transformer & MCC to power turbine Accessories. |
| C.T.'s, Draw Out P.T.'s. |
| Lightning Arrestors, & Surge Capacitor |

**Table 12. Grounding,** XQ5200 Mobile Power Unit

| | |
|---|---|
| Option 1 | Low Resistance grounding |
| Option 2 | Ungrounded generator |

**Table 13. Protective Relays,** XQ5200 Mobile Power Unit

| ***Beckwith M-3425*** | ***Designation*** |
|---|---|
| Impedance | 21 |
| Undervoltage | 27 |
| RPR | 32 |
| Loss of Field Protection | 40 |
| Negative Phase Sequence | 46 |
| PT Blown Fuse | 60FL |
| Phase overcurrent | 51V |
| Inadvertent energization | 50/27 |
| Ground Overcurrent | 50N, 51N |
| Overvoltage | 59 |
| Bus Ground Fault Detection | 59N |
| Over/Under Frequency | 81 |
| Phase Differential overcurrent | 87 |
| Ground differential Settings Programmable for resistance grounding or ungrounded operation. | 87GD |
| Basler BE-1, Overcurrent | 50/51B |

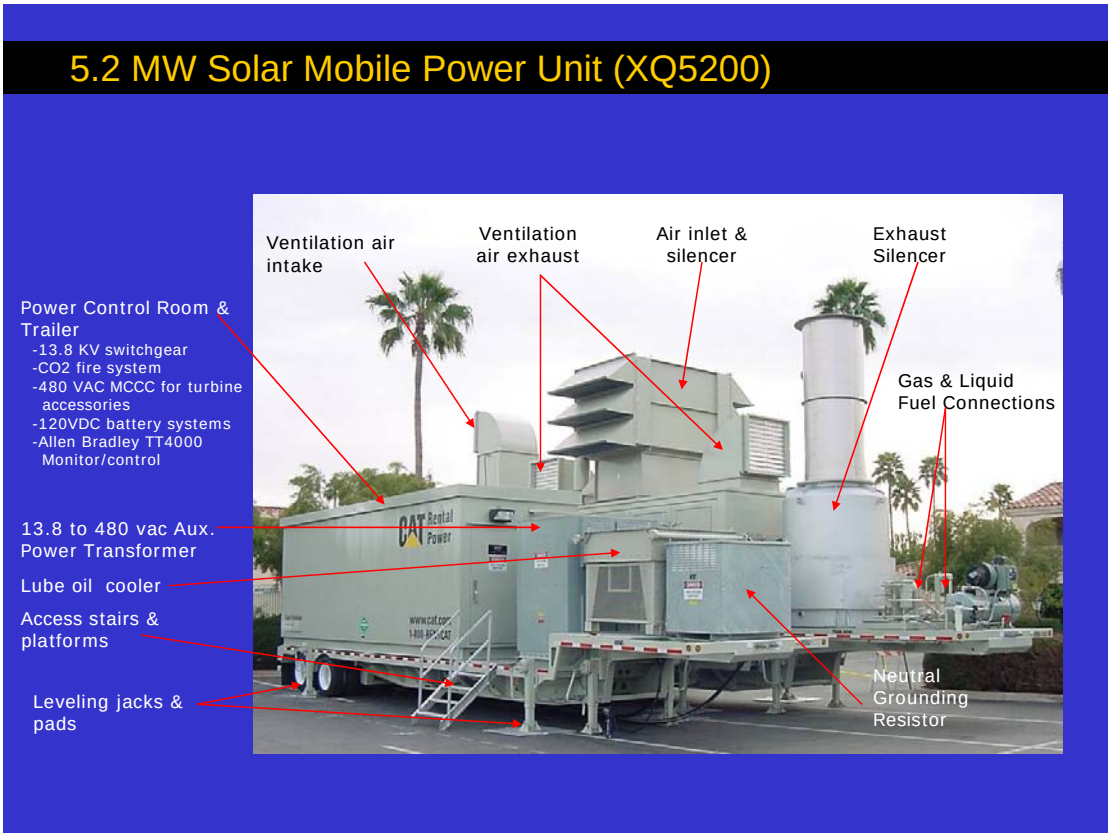
*Please request site and application specific data for formal proposals.*

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**Table 14. XQ5200 Rental Power Benefits**

| *Flexible Rental Solution* | *Easy to Install & Relocate* |
|---|---|
| Short & Long Term Rental Options | Highway transportable |
| Rental/Purchase Options | 3 to 5 day setup |
| 50 or 60 hz. Units available | No concrete foundation required |
| ***Environmentally Friendly*** | ***Complete Systems Solution*** |
| Low Emissions, 25 ppmv Nox | Set-up & Commissioning |
| Quiet Operation, 87 dba @ 3 ft. (1M) | Maintenance Included |
| No Visible Emissions | Operators available |
| Low Profile Design | Site Preparation (if needed) |
| Easy to Permit | Transformers (if needed) |
| ***Worldwide Support*** | ***Operational Features*** |
| Caterpillar's Worldwide Rental Network | On line in six minutes |
| Solar Turbines Worldwide Service Network | Range of Control System Options<br>KVAR Control & KW Control |

**Table 15. XQ5200 Photo Overview**




*Please request site and application specific data for formal proposals.*





# TAURUS 60 MOBILE POWER UNIT

Turbine Generator Set Module (Basic Package):

The Taurus 60 Industrial Power Generator (PG) is a compact, rugged gas turbine generator set that has been designed to meet the requirements for industrial power generation applications. The gas turbine engine, gearbox, generator, control system, fuel system, lubrication system, start system, and ancillary equipment are included in the package.

Features included in this proposal are:

**Base.** The base provides structural support for the Taurus 60 gas turbine engine, gear box, generator, enclosure, and all operating systems. The base is manufactured by Solar using structural steel with welds per AWS D1.1.

Drip pans are welded beneath the package frame to collect potential liquid spills. The drip pans also provide a tight seal for containment of fire suppression agent.

**Piping.** All tubing and piping up to 4 inches nominal diameter is stainless steel. Package piping is designed and fabricated to ANSI B31.3.

**Tube Fittings.** All tube connections use compression fittings. Tube fittings are zinc plated carbon steel.

*Note: Throughout the proposal, all references to the package orientation (left, right, clockwise, counterclockwise, etc.) are based on standing at the "aft" (e.g. turbine exhaust) end of the package looking forward.*

**Electrical System.** The Taurus 60 IPG generator set is designed to comply with the requirements of the National Electrical Code and is intended to be installed in a non-hazardous location per NFPA 37.

Unless otherwise noted package motors and heaters are rated for 480 Vac, 60 Hertz, 3 phase. Unless otherwise noted single phase loads are rated for 220 Vac, 60 Hertz.

## GAS TURBINE ENGINE

The Taurus 60 gas turbine engine is a single shaft axial flow engine. The output gearbox, including accessory drive pads, is a separate, close-coupled unit located at the inlet end of the turbine.

The engine assembly consists of:

- Gear unit with accessory drive pads
- Air inlet collector with flexible flange connection
- Axially split case in the vertical plane, twelve-stage axial flow compressor with variable geometry control on inlet guide vanes and first three rows of stators
- Annular combustor with 12 fuel injectors
- Three-stage turbine assembly
- Turbine exhaust collector

The components of the Taurus 60 engine are maintained in accurate alignment by mating flanges with pilot surfaces and are bolted together to form a rigid assembly. The speed reducing gear box is driven by the compressor rotor shaft. Accessory pads drive the main lube oil pump and other accessories, depending on the application, and supports the starter motor.

The gas turbine output shaft is mechanically coupled to both the compressor and turbine sections of the engine to form a "solid" or "single" shaft configuration. This feature enhances speed stability and response under constant and varying load conditions -- a highly desirable feature in generator applications requiring precise frequency control.

## SPEED REDUCING GEARBOX

The speed-reducing gearbox is an epicyclic star-gear industrial design manufactured by Solar specifically for the Taurus 60 PG generator. The gearbox mounts directly on the Taurus 60 gas turbine to reduce engine speed to 1800 rpm (60 Hz).

## GENERATOR

- Salient Pole, 3 Phase Generator with the follow characteristics:

**Rating.** The generator is rated per NEMA standards so that the generator will not limit turbine performance over the range of site ambient temperatures. Generator standard features include:

- Sleeve Bearings with pressure fed sumps
- Six-lead WYE connection
- Terminal box
- Form wound stator windings
- Damper windings
- Rotor balance to 125% rated speed
- Permanent magnet pilot exciter
- Anti-condensation space heaters





- 300% short circuit capability for 10 seconds
- Overload capacity per NEMA:
  - 150% rated current for 1 minute
    - 110% for 2 hours

**Voltage Regulator Characteristics**

- Solid state
- Single-phase sensing
- ±10% voltage adjustment range
- 0.5% steady state voltage regulation
- Reactive load sharing to within 5% nameplate rating
- Crosscurrent compensation capability

**Wave Form Characteristics**

- Deviation Factor [maximum] 6%
- Harmonic Content [maximum] 3%
- Telephone Interference Factor 50
- Balanced Residual 75

**Voltage Drift.** The change in voltage will not exceed 1.0% over a 30 minute period when the generator is operating at rated voltage and 0.8 to 1.0 power factor and with a constant load between no load and full rated load.

**Generator Construction.** An open drip proof generator per NEMA standards is provided.

**Generator Voltage.** The generator output is 12,470 – 13,800 Volt, 3 phase, 60 Hz. Insulation conforms to NEMA class F with class F ($105^0$C) temperature rise.

**FUEL SYSTEM**

The fuel system, in conjunction with the electrical control system, includes all necessary components to control the fuel pressure, to schedule fuel flow during start-up, and to modulate fuel flow during operation.

**Dual Natural Gas or Liquid Fuel.** A system capable of operating on natural gas or liquid fuel is provided with all components necessary to maintain turbine speed to provide a constant generator output frequency and/or load depending on the generator set mode of operation. Solar's Specification ES 9-98 contains specific requirements for fuel and combustion air. The dual fuel system, which operates on either natural gas or liquid fuel, includes the controls for automatic changeover from one type of fuel to the other during operation.





**Natural Gas Fuel.** The natural gas fuel system includes:

- Primary fuel shutoff valve
- Pilot-operated secondary fuel shutoff valve
- Electronic actuated fuel control valve
- 10-micron pilot gas filter
- Compressor discharge pressure gauge
- 12 fuel injector assemblies
- Valve check pressure switch
- Low gas fuel pressure alarm and transfer software for use with discrete input signal from user fuel source
- High gas fuel pressure shutdown switch
- Gas strainer

**System Requirements**

- Requires a constant supply of gas at a maximum flow demand rate of 32.2 $nm^3$/min (1200 scfm) at 1725 kPa gauge (250 psig) minimum and 2070 kPa gauge (300 psig) maximum pressure. Gas fuel pressure is used to operate the fuel system pilot valve.
- The gas fuel should be free of sulfur, contaminants, entrained water, and liquid hydrocarbons
- Gas fuel must conform to Solar's Specification ES 9-98

**Liquid Fuel System**. The Liquid Fuel System includes:

- 7.5-hp VFD ac motor-driven main fuel pump
- 12 fuel injector assemblies
- Duplex low pressure fuel filters with replaceable 10-micron filter elements
- Low pressure fuel filter changeover valve
- Simplex 25-micron high pressure fuel filter
- Low fuel pressure transmitter
- Liquid fuel solenoid-operated valves -- main fuel shutoff, purge, bypass, and torch shutoff valves
- Drain to off skid liquid fuel purge tank (supplied by others)

**System Requirements**

- Requires a constant supply of liquid fuel at a maximum flow demand rate of 30.3 L/min (8.0 gpm).
- Fuel must conform to Solar's Specification ES 9-98. Typical acceptable fuels include:
  - Grades 1 and 2 fuel oil
  - Grades 1 and 2 diesel
  - Kerosene (JP-8, JP-5, or commercial grade)

## NEC, NON-HAZARDOUS ELECTRICAL CLASSIFCATION

- CSA and $CSA_{NRTL}$ Certification

## DIRECT START SYSTEM

A direct drive AC motor is provided to start the gas turbine engine. A variable frequency drive [VFD] motor controller is included. The control system provides all required sequencing to quickly and reliably start the turbine.

## LUBE OIL SYSTEM

A complete lube oil system suitable for operation with lube oil conforming to Solar's Specification ES 9-224 is included. The lube oil system provides oil to the bearings in the Taurus 60 gas turbine engine, gear box and generator. Instrumentation, flow control and on frame piping are included.

**Main Lube Oil Pump.** An engine driven lube oil pump is provided with suction strainer.

**Pre/Post Lube Pump.** A 2 hp (1.5 kW) AC motor driven pump is provided to supply lube oil flow prior to start up and after shutdown of the gas turbine.

**Post Lube Backup Pump.** A 1.5 hp (1.1 kW) DC motor driven pump is provided to supply post operation lube oil flow in the event of power failure. Power is provided by a 120 Vdc battery system.

**Drain Line Sight Glasses.** Sight glasses are provided on the drain lines from all gas turbine, generator and gear box bearings. Note that some of the gas turbine bearings have a common drain line.

**Lube Oil Tank.** A carbon steel lube oil tank is provided integral with the package frame. Lube oil level indicator, fill connection with inlet strainer and drain connections are included.

**Lube Oil Tank Heater.** A thermostatically controlled 4.5 kW lube oil tank heater is provided.

**Lube Oil Cooler.** An air/oil lube oil cooler is provided. A 5-hp (3.7 kW) AC motor drives the fan. The lube oil cooler is mounted on the Power Control Room trailer. Quick Disconnect-Interconnect hoses between the Power Control Room trailer and Turbine trailer is included.

**Lube Oil Type.** Lube oil is included. The lube oil complies with Solar specification ES 9-224. This project will be configured for petroleum base oil, viscosity grade C32.

**Lube Oil Filter**. A simplex 5 micron oil filter is provided with drain, fill and vent valves, differential pressure alarm transmitter.

**PLC BASED CONTROL SYSTEM (with 120 VDC Battery Supply):**

Solar's Turbotronic$^{TM}$ control system is provided. The Turbotronic control system is a highly integrated programmable logic controller [PLC] based control system. The control system is installed on the package frame to minimize interconnect wiring. The control system includes a microprocessor, remote communications modules, chassis based and flex input/output modules, line synchronization module, power supplies and a hardware backup shutdown system. The control system provides for control of all phases of package operation to include start and shutdown sequencing, normal operation, and malfunction shutdown.

**Local Display**. The control system is installed on the package frame in weather proof enclosures. A digital control panel [DCP] with all necessary switches and indicators is provided. In addition to display of "first out" malfunctions, the DCP can display:

System summary/normal running data
System status
Digital display of engine and generator parameters
Alarms and Shutdowns

**Audible Alarm.** An audible alarm horn is provided to sound whenever the unit has an alarm or shutdown condition. A horn silence push button is mounted on the face of the control panel.

**Vibration Monitoring.** Vibration monitoring is provided to include three proximity probes, one per bearing, on the engine. One accelerometer is provided with the gearbox. Two velocity transducers, one per bearing are provided with the generator. Preset warning indications and malfunction shutdown initiations are provided.





**Temperature Monitoring.** Temperature monitoring is provided to include the engine thrust bearing, lube oil header, generator bearings and stator windings. Preset warning indications and malfunction shutdown initiations are provided. Ambient, lube oil tank and enclosure temperatures are also monitored.

## GENERATOR CONTROL AND MONITORING SYSTEM

Integrated monitoring and control of the generator is provided using a specially designed module in the PLC to receive input data from potential and current transformers. The system calculates real and reactive power, power factor and the variables required for synchronization.

**Automatic Synchronizing.** An automatic synchronizer is provided with the control system to automatically synchronize the unit to the bus through push-button control on the digital control panel [DCP] or by receipt of an appropriate remote signal. A synch check relay is provided as an additional permissive and for backup protection.

**Motorized Voltage Adjust.** Raise/lower voltage push button control is provided on the digital control panel to control a motorized potentiometer for voltage control. An additional raise/lower switch, supplied by others, may be used to control voltage from a remote location.

**KW Controller.** A kW controller is provided to control the real load (kW) on the generator set while operating in parallel with a utility or other large source. The kW controller monitors the load carried by the generator set and adjusts the turbine's fuel flow to maintain a constant load as plant load changes. Protection against excessive kW load while in parallel with a large source is provided by the control system "T5" temperature limiter. The kW control system provides additional operational flexibility by allowing unit kW load level to be set at any desired level within the capacity if the unit. The kilowatt load level select switch and level adjustment is located on the digital control panel.

**KVAR/Power Factor Controller.** A kVAR/power factor controller is provided to maintain a constant reactive load (kVAR) output or constant power factor (pf) on the generator set while the unit is operating in parallel with a utility or other large source. The controller applies a signal directly to the voltage regulator adjust circuit to maintain a constant reactive load or power factor with changes in the infinite bus voltage level. The system incorporates a set point adjust rheostat to set the desired kVAR or pf, a selector switch to choose kVAR or pf control mode, and a switch to turn the controller on and off.

**Supervisory Interface**. An RS 232C/422 interface module is provided to give the user's supervisory computer access, such as SCADA, to the Turbotronic control system data. Limited control capability is provided to allow the supervisory computer to start and stop the unit, reset alarms, and raise/lower speed and load set points.





The communications protocol is Allen Bradley's DF1.

The interface module may be located up to 10,000 feet (3,048 meters) from the turbine control system and located up to 50 feet (15 meters) from the supervisory computer for the RS 232C module or 4,000 feet (1,219 meters) for the RS 422 module.

**Engine Performance Map.** A display of real time engine performance is provided on the remote VDT. Performance data is corrected to standard conditions. The performance map is provided for reference and to monitor trends.

**Historical Displays.** The following maintenance and diagnostic programs are provided to assist in routine monitoring of gas turbine condition as well as to assist in making informed predictions of the future health of the unit.

Run Time Display - This feature provides a four channel strip chart format display on the VDT. It provides simultaneous, real time display of multiple operator selected parameters.

Elapsed Time Display - This feature is used for plotting and determining trends in the unit's performance. Selected parameters are stored on disk regardless of whether the unit is running. Data is saved at pre-determined intervals and can be retrieved for analysis.

Predictive Trend Monitoring - This feature analyzes historical data and approximates future analog trends. Deteriorating trends will result in a display that has the trend line intersecting a predetermined alarm or shutdown level at an indicated future time.

**Remote VDT and Control.** A remote video display terminal [VDT] is also provided. The VDT displays an expanded set of operating information including all of the data available on the panel and provides the capability to start and stop the unit, initiate automatic synchronization and open circuit breaker. Data which may be displayed on the remote VDT includes:

Turbine Engine Parameters:

| | |
|---|---|
| T5 temperature | Fuel actuator current |
| Lube oil temperature | Fuel actuator minimum setting |
| Lube oil tank temperature | Control mode |
| Lube oil pressure | Operation mode |
| Start sequence status | Status lights |

Generator Parameters

| | |
|---|---|
| KW load | Generator Voltage, each phase |
| KVA/KVAR | Average Voltage |

| | |
|---|---|
| Power factor | Generator current, each phase |
| Frequency | Average current |

Commands which may be sent to the PLC include:

Start
Stop
Initiate synchronization
Open circuit breaker
Raise or lower kW control setpoint

The remote VDT consists of an industrial type personal computer mounted in the Power Control Room trailer.

**Remote Dial Up Monitoring and Control.** Included in the Remote Video Display is the ability to dial the unit from a remote location, display monitoring screens, and execute control actions to start and stop the unit, reset alarms, and raise/lower speed and load set points. The VDT is connected to the generator set PLC via Controlnet. The Power Control Room is equipped with a telephone line connection.

## TURBINE COMPRESSOR CLEANING

An On-Crank and On-Line engine cleaning system is provided. The systems are independent of each other and include separate distribution manifolds and injectors in the engine air inlet collector and associated on-skid plumbing to deliver water and/or approved cleaning solution to the manifold. Water and cleaning solutions used for engine cleaning must comply with Solar Specification ES 9-62. Requires Optional Water Wash Supply Cart (one per site)

## WEATHERPROOF ACOUSTIC ENCLOSURE

Ventilation Silencers and Fans, Lights, Fire Detection and Gas Monitoring System with Auto Shutdown and Fuel Supply Shutoff, High Temperature Detection and Alarm, CO2 Fire Suppression System.

**Language.** Package labels and screen displays will be in English.

## COMBUSTION INLET SYSTEM

- High Efficiency Barrier Filter and Silencer mounted on top of Generator Set enclosure.

## EXHAUST SYSTEM

Included is a trailer mounted exhaust silencer with a 25-foot Stainless Steel Rains Stack.

The stack is equipped with flanged emission ports for emission sampling.

**FACTORY TESTING** (Performed on new units @ time of Manufacture)

**Gas Turbine Engine Testing.** The gas turbine engine is tested in accordance with Solar specifications to confirm that power, heat rate, and vibration levels meet Solar standards.

**Generator Testing**. The generator is tested in accordance with IEEE Standard Specifications and Solar's specifications at the manufacturer's plant. These tests satisfy requirements for NEMA and Solar. Supplier testing is under periodic Solar quality control review to ensure compliance with required specifications.

**Radiography Inspection.** Radiographic inspection is performed in accordance with ASME Section V. Five (5) percent of each welder's work (circumferential butt welds only) is inspected by radiographic examination in accordance with ANSI/ASME B31.3. The specific manifolds on a given unit may or may not be part of the 5% of each welder's work which is examined.

**Quality Assurance.** All testing operations are conducted under the direct control of Solar's Quality Assurance Activity. This Activity ensures compliance with the specified test limits and procedures.

In addition to final in-plant testing of the finished generator set, Quality Control engineers maintain surveillance over the manufacture of all purchased parts and subassemblies, and are responsible for functional testing of incoming components. The same rigid standards applied to parts manufactured by Solar are applied to all parts from suppliers.

**TURBINE TRAILER (Model TK95LCS)**

- Tri-Axle Transport Trailer with Two Axle Pivoting Booster
- Trailer Length 48’ + 14’1” Booster (removable at site)
- Width 8’6”, 9’0” across trailer axles
- 133” Swing Clearance
- 49” 5$^{th}$ wheel Height (loaded)
- Air Ride Suspension and Air Raise and Lowering Kit
- Steel Disc Wheels with 275/70R x 22.5 Tire
- Three Tail Light Package
- Landing Gear (2)
- 6 Additional Landing Gears with Soil Bearing Plates for Leveling/Stabilization at Site
- Overall transport height: 14’2”
- Approximate transport weight: 118,000 lbs (without tractor)

**POWER CONTROL MODULE** (consists of the following):

- Power Control Room (PCR) mounted on Two Axle Transport Trailer.
- Power Control Room HVAC system
- Generator Main Circuit Breaker. Single interface point to power grid
- Auxiliary Transformer Feeder Circuit Breaker
- Bus PTs, Feeder CTs, Metering CTs and PTs
- Beckwith M-3425 Protective Relay Module with the following relays:

    - Impedance (21)
    - Reverse Power Protection (32)
    - Loss of Field Protection (40)
    - Negative Phase Sequence Protection (46)
    - PT Blown Fuse Protection (60)
    - Time Overcurrent Protection (50/51 V)
    - Neutral Overcurrent Protection (51 N) – utilized in grounded site design
    - Bus Ground Fault Detection (59N) – utilized in ungrounded site design
    - Generator Differential Fault Protection (87 G)
    - One High Speed Tripping Relay (86) for Circuit Breaker Trip, Lockout, and Turbine Shutdown Settings, Programming, and Testing are included.

- Lightning Arrestor and Surge Capacitor
- Motor Control Center. Serves Turbine Generator Auxiliary Loads
- 120VDC Turbine Generator Battery System with Charger
- Dedicated 120VDC Switchgear Battery System with Charger
- Start Motor Variable Frequency Drive (VFD)
- DC Backup Lube Oil Pump Contactor
- Interior Lighting. Photocell Controlled Exterior Lighting at Access Doors
- Emergency Eyewash Station

**Ancillary Equipment.** Installed onto the Power Control Room Module are the following:

- Gas Turbine Lube Oil Cooler
- Neutral Ground Resistor
- Auxiliary Load Transformer

**Power Control Room Trailer (Model TK70LCS)**

- Two Axle Transport Trailer
- Trailer Length 46’ Overall
- Width 8’6”
- 49” 5$^{th}$ wheel Height (loaded)
- Air Ride Suspension and Air Raise and Lower Kit





- Steel Disc Wheels with 255/70R x 22.5 Tires
- Three Tail Light Package
- Landing Gear
- 4 Additional Landing Gears with Soil Bearing Plates for Leveling/Stabilization at Site
- Overall Transport Height: 14’0”
- Approximate transport weight: 48,000 lbs. (without tractor)

**On site commissioning**

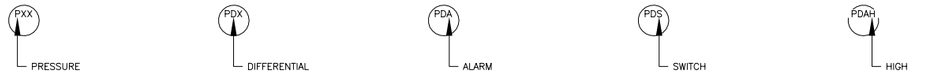
- Solar’s Mobile Power Unit is designed for rapid setup and commissioning. The turbine package(s) proposed has been commissioned previously by Solar Factory Service Engineers. A checklist outlining the proposed setup & commissioning procedure is attached for your reference.

DWG. NO. 59731-1500-F001 SH. REV.

## REVISIONS

| ZONE | LTR. | DESCRIPTION | DATE | APPROVED |
|---|---|---|---|---|
| | B | RECORD DRAWING | 03-30-01 | DFH |
| | C | NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY. | 1-15-03 | GH |

## INSTRUMENTATION IDENTIFICATION




**FIRST LETTER MEASURED OR INITIATING VARIABLE**

A – ANALYSIS
B – BURNER
C – USER'S CHOICE
D – USER'S CHOICE
E – VOLTAGE
F – FLOW RATE
G – USER'S CHOICE
H – HAND
I – CURRENT (ELECTRICAL)
J – POWER
K – TIME, TIME SCHEDULE
L – LEVEL
M – USER'S CHOICE
N – USER'S CHOICE
O – USER'S CHOICE
P – PRESSURE, VACUUM
Q – QUANTITY
R – RADIATION
S – SPEED FREQUENCY
T – TEMPERATURE
U – MULTIVARIABLE
V – VIBRATION
W – WEIGHT, FORCE
X – UNCLASSIFIED
Y – EVENT, STATE OR PRESENCE
Z – POSITION, DIMENSION

**FIRST LETTER MODIFIER**

D – DIFFERENTIAL
F – RATIO
J – SCAN
K – TIME RATE OF CHANGE
M – MOMENTARY
Q – INTEGRATE, TOTALIZE
S – SAFETY
X – X-AXIS
Y – Y-AXIS
Z – Z-AXIS

**SUCCEEDING – LETTERS READOUT OR PASSIVE FUNCTION**

A – ALARM
B – USER'S CHOICE
E – SENSOR (PRIMARY ELEMENT)
G – GLASS, VIEWING DEVICE
I – INDICATE
L – LIGHT
N – USER'S CHOICE
O – ORIFICE, RESTRICTION
P – POINT (TEST) CONNECTION
R – RECORD
U – MULTIFUNCTION
W – WELL
X – UNCLASSIFIED

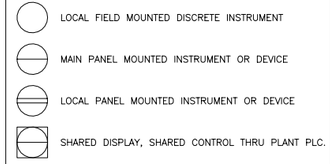
**SUCCEEDING – LETTERS OUTPUT FUNCTION**

B – USER'S CHOICE
C – CONTROL
K – CONTROL STATION
N – USER'S CHOICE
S – SWITCH
T – TRANSMIT
U – MULTIFUNCTION
V – VALVE, DAMPER, LOUVER
X – UNCLASSIFIED
Y – RELAY, COMPUTE, CONVERT
Z – UNCLASSIFIED

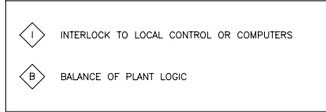
**SUCCEEDING – LETTERS MODIFIER**

B – USER'S CHOICE
H – HIGH, VALVE OPEN
L – LOW, VALVE OPEN
M – MIDDLE, INTERMEDIATE
N – USER'S CHOICE
U – MULTIFUNCTION
X – UNCLASSIFIED

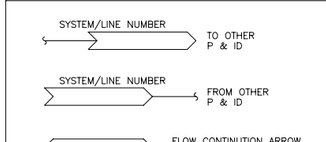
## INSTRUMENTATION SYMBOLS



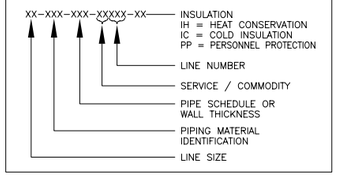

## INSTRUMENT & CONTROL INTERLOCKS



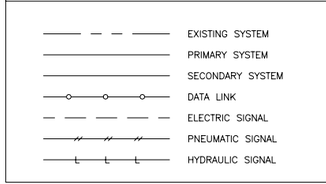

## CONTINUATION ARROWS




## PIPING LINE NUMBER




## PIPING & INSTRUMENT LINES




## ABBREVIATIONS

| ABBREV. | DESCRIPTION |
|---|---|
| A/C | ASPHALT CONCRETE |
| BLDG. | BUILDING |
| ℄ | CENTER LINE |
| C.L. | CHAIN LINK |
| COMP. | COMPRESSOR |
| CONC. | CONCRETE |
| CMU | CONCRETE MASONRY UNIT |
| CONN. | CONNECTION |
| CONT. | CONTINUOUS |
| CPLG. | COUPLING |
| CU. FT. | CUBIC FEET |
| DIA. OR ø | DIAMETER |
| DEPT. | DEPARTMENT |
| DWG. | DRAWING |
| EA. | EACH |
| ECC. | ECCENTRIC |
| ELEV. | ELEVATION |
| E.O. | EDGE OF |
| ESD | EMERGENCY SHUTDOWN |
| ESDPB | EMERGENCY SHUTDOWN PUSH BUTTON |
| ENCL. | ENCLOSURE |
| EXIST. | EXISTING |
| F.C. | FAIL CLOSED |
| F.O. | FAIL OPEN |
| F.P.T. | FEMALE PIPE THREADED |
| F.F. | FLAT FACE |
| F.O.B. | FLAT ON BOTTOM |
| F.O.T. | FLAT ON TOP |
| FIG. | FIGURE |
| F.M.U. | FITTING MAKE-UP |
| FLG. | FLANGE |
| FT. | FOOT |
| F.O.M. | FACE OF MASONRY |
| GALV. | GALVANIZED |
| GND. | GROUND |
| H | HIGH |
| H.P. | HIGH PRESSURE |
| HORIZ. | HORIZONTAL |
| I.D. | INSIDE DIAMETER |
| L/S | LANDSCAPE |
| KVA | KILOVOLT – AMPS |
| LAV. | LAVATORY |
| L.C. | LOCKED CLOSED |
| L.O. | LOCKED OPEN |
| L | LONG |
| M.B. | MACHINE BOLT |
| M/U | MAKE-UP |
| M.O. | MASONRY OPENING |
| MAX. | MAXIMUM |
| MIN. | MINIMUM |
| M.P.T. | MALE PIPE THREAD |
| MTR. | MOTOR |
| NPT | NATIONAL PIPE THREAD |
| N/A | NOT APPLICABLE |
| N.C. | NORMALLY CLOSED |
| N.O. | NORMALLY OPEN |
| N.T.S. | NOT TO SCALE |
| NO. | NUMBER |
| O.C. | ON CENTER |
| P/N | PART NUMBER |
| ℙ | PLATE |
| P.B.E. | PLAIN BOTH ENDS |
| P.O.E. | PLAIN ONE END |
| P.O.C | POINT OF CONNECTION |
| PE. | POLYETHYLENE |
| PVC. | POLYVINYLCHLORIDE |
| # | POUND |
| PSI | POUNDS PER SQUARE INCH |
| P.B. | PUSH BUTTON |
| R.F. | RAISED FACE |
| RED. | REDUCING |
| REF. | REFERENCE |
| RCP | REINFORCED CONCRETE PIPE |
| REINF. | REINFORCEMENT |
| SCH. | SCHEDULE |
| SEC. | SECTION |
| SIM. | SIMILAR |
| SPR. | SPRINKLERED |
| SQ. | SQUARE |
| SQ. FT. | SQUARE FEET |
| SCFH | STANDARD CUBIC FEET PER HOUR |
| STD. | STANDARD |
| SS | STAINLESS STEEL |
| THK. | THICK |
| THD. | THREADED |
| THRU. | THROUGH |
| XFMR OR XFORMER | TRANSFORMER |
| TYP. | TYPICAL |
| U/G | UNDERGROUND |
| U.O.N. | UNLESS OTHERWISE NOTED |
| VERT. | VERTICAL |
| W | WIDE |
| W/ | WITH |

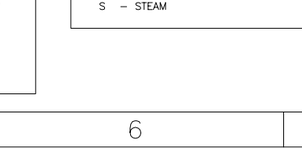
## MISCELLANEOUS SYMBOLS

| ITEM | DESCRIPTION |
|---|---|
| | CORIOLIS FLOW METER |
| | ORIFICE |
| | TURBINE FLOW METER |
| | FLANGE |
| | UNION |
| | CAP WELDED |
| | CAP THREAED OR SOCKET WELDED |
| | BLIND FLANGE |
| | HOSE CONNECTION |
| | CONCENTRIC REDUCER |
| | ECCENTRIC REDUCER |
| | FLEXIBLE CONNECTOR |
| | EXPANSION JOINT (BELLOWS TYPE) |
| | INSULATED LINE |
| E | ELECTRIC HEAT TRACED LINE |
| | Y-TYPE STRAINER |
| | CENTRIFUGAL PUMP |
| OR | POSITIVE DISPLACEMENT PUMP |
| | EDUCTOR |
| | CENTRIFUGAL FAN |
| | AXIAL FAN |
| | POINT OF CONNECTION |
| LC | LOCKED CLOSED |
| LO | LOCKED OPEN |
| NC | NORMALLY CLOSED |
| NO | NORMALLY OPEN |
| CS CS | SPEC/SCOPE OF SUPPLY BREAK |
| CU | COPPER |
| CS | CARBON STEEL |
| SS | STAINLESS STEEL |
| IA | INSTRUMENTS AIR SUPPLY |

## VALVE SYMBOLS

| OPEN | CLOSED | TYPE |
|---|---|---|
| | | ANGLE |
| | | BALL |
| | NC | BUTTERFLY |
| | N/A | CHECK |
| | | GATE OR UNSPECIFIED |
| | | GAUGE ROOT (W/INTEGRAL VENT) |
| | | GLOBE |
| | | NEEDLE |
| | | PLUG |
| | | REGULATING (FLOW) |
| | N/A | SAFETY/RELIEF |
| | N/A | STOP-CHECK (NON-RETURN) (ANGLE) |
| | N/A | STOP-CHECK (NON-RETURN) (Y-PATTERN) |
| | | THREE-WAY |
| | | FOUR-WAY |

## CONTROL VALVE OPERATORS




## PIPING MATERIAL IDENTIFICATION

| PRESSURE CLASS | MATERIAL | ENDS |
|---|---|---|
| A – 150# | 1 – CARBON STEEL | 0 – RAISED |
| B – 300# | 2 – LOW TEMPERATURE | 1 – FLAT FACE |
| C – 400# | 3 – COPPER OR BRONZE | 2 – RING TYPE JOINT |
| D – 600# | 4 – GALVANIZED | 3 – SCREWED END |
| E – 900# | 5 – 304 STAINLESS STEEL | 4 – SOCKET-WELD END |
| F – 1500# | 6 – NACE SPEC. | 5 – BUTT-WELD END |
| G – 2500# | 7 – 316 L STAINLESS STEEL | 6 – WAFER |
| S – OPEN ATMOSPHERE | 8 – SPECIAL | 7 – SPECIAL |
| T – TO BE ESPECIFIED AS REQUIERED | 9 – SPECIAL | 8 – SPECIAL |
| | | 9 – SPECIAL |

## SERVICE / COMMODITY

P – PROCESS GAS AND LIQUID
EX – EXHAUST
D – DRAIN
A – AIR
CW – COOLING WATER
F – FUEL GAS AND LIQUID
PW – POTABLE WATER
S – STEAM
FW – FEED WATER
LO – LUBE OIL
V – VENT AND FLARE
CF – CLEANING FLUID
FE – FIRE EXTINGUISHANT
TW – TREATED (DEMINERALIZED) WATER

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PETERSON
POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

DATA CONTROL LEVEL | RELEASE STAMP

| | | |
|---|---|---|
| CONTRACT NO. | | |
| DFTR. G MENDOZA | 11-30-00 | |
| CHKR. J PLESCIA | 12-22-00 | |
| LYT. | | |
| ENGR. D.F. HAAS | 11-30-00 | |
| ME | | |
| PLOT DATE | 03-30-01 | |
| PLOT SCALE | 1=1 | |
| CUSTOMER | | |

MODEL LEVEL
LAYOUT
NHA
MODEL
CADDS IDENT. 59731F001

Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California
92186-5376

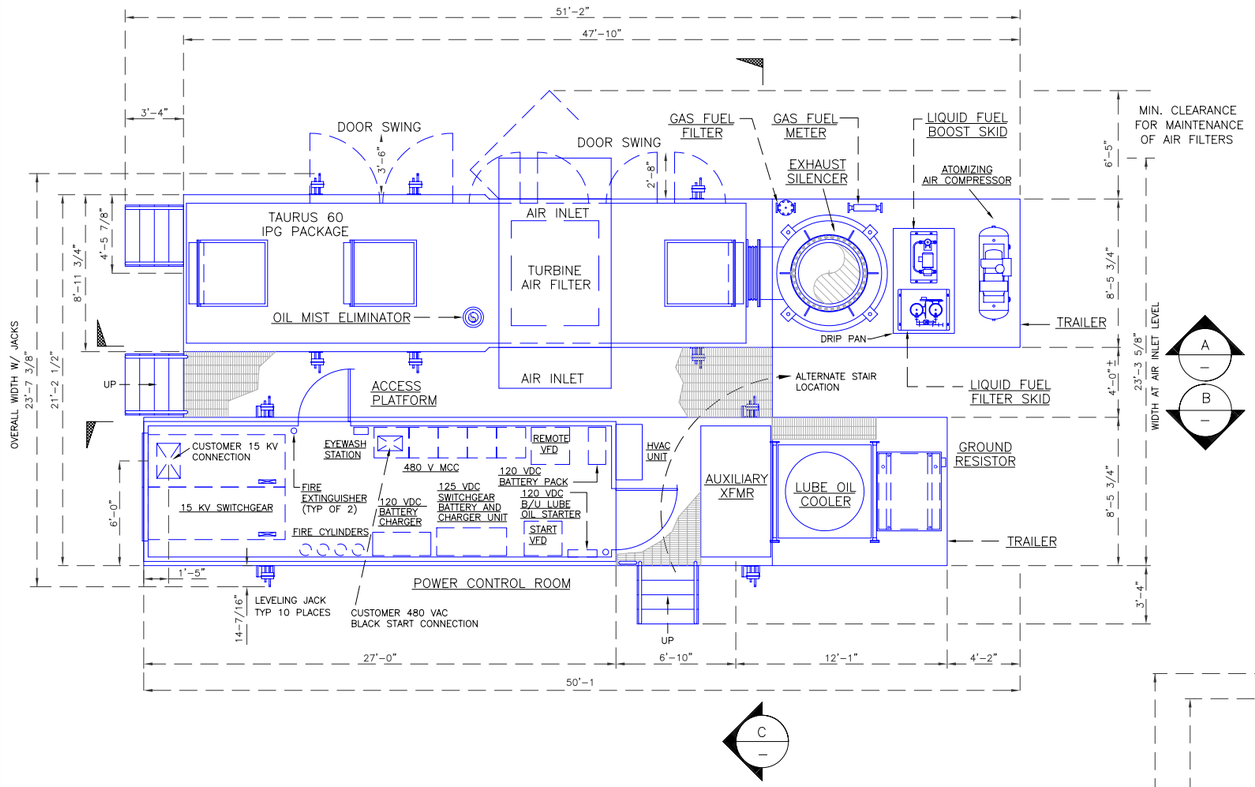
LEGEND SHEET
TAURUS 60 – DUAL FUEL
MOBILE UNIT

SIZE D | CAGE NO. | DWG. NO. 59731-1500-F001
SCALE: NONE | TOTAL WT. | SHEET OF

DWG. NO. 59731-1500-M001 SH. REV.

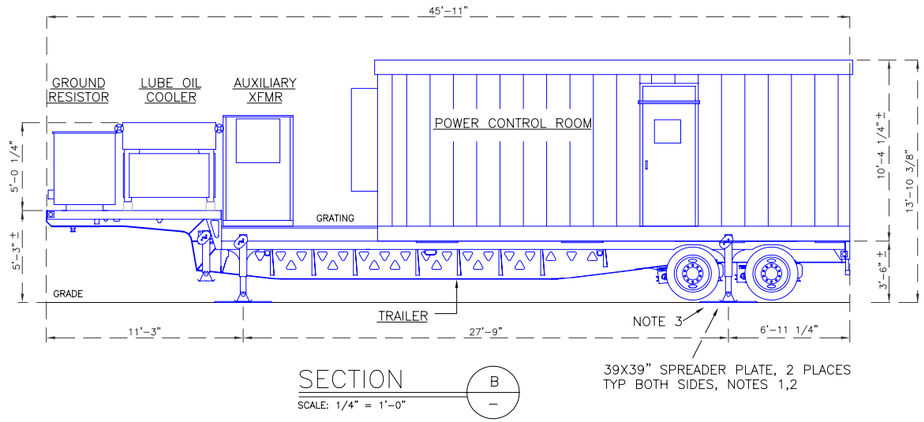
REVISIONS

| ZONE | LTR. | DESCRIPTION | DATE | APPROVED |
|---|---|---|---|---|
| | A | ISSUED FOR REVIEW | 12-22-00 | DFH |
| | B | RECORD DRAWING | 03-30-01 | DFH |
| | C | ROTATED GENERATOR EXHAUST ELBOW SILENCER | 05-22-01 | DFH |
| | D | NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY. | 1-15-03 | GH |

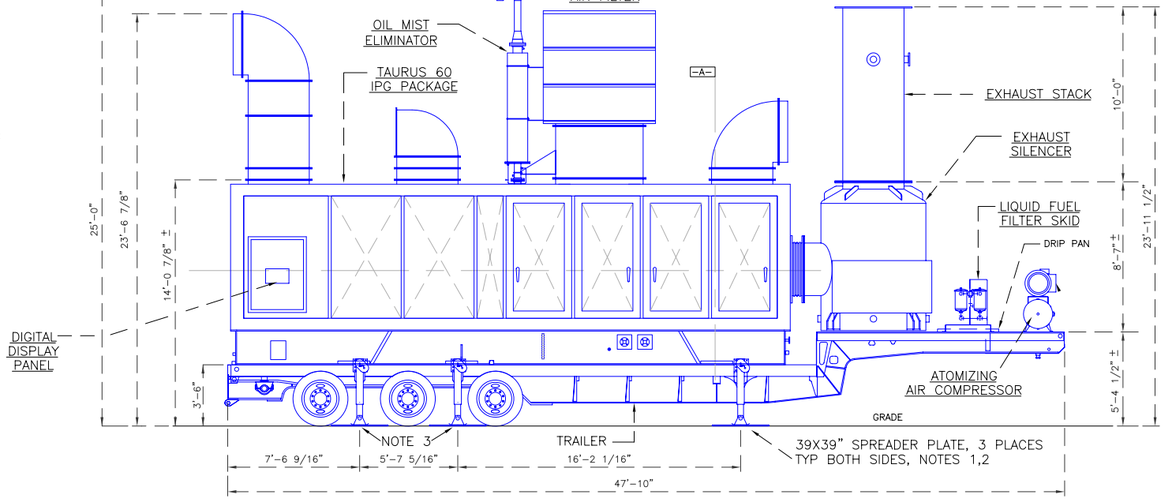



## EQUIPMENT GENERAL ARRANGEMENT PLAN – TAURUS 60 MOBILE UNIT

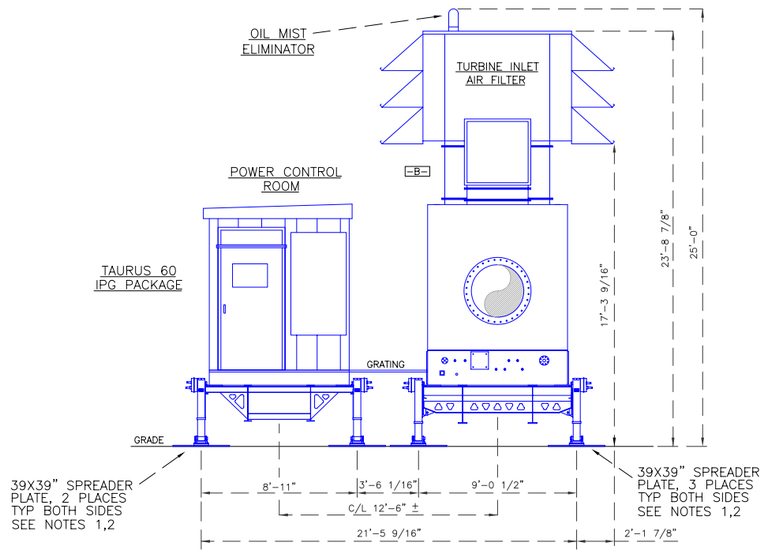
SCALE: 1/4" = 1'-0"




SECTION B – SCALE: 1/4" = 1'-0"




SECTION A – SCALE: 1/4" = 1'-0"




SECTION C – SCALE: 1/4" = 1'-0"

NOTES:
1. SPREADER PLATES ARE PROVIDED BY SOLAR
2. SOIL COMPACTION SHALL BE A MINIMUM OF 2500 LBS/SQ.FT. TO SUPPORT TRAILER PACKAGE.
3. SPREADER PLATES ORIENTED ON THE DIAGONAL AT THIS LOCATION TO AVOID TIRE INTERFERENCE. TYP. BOTH SIDES.

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| DATA CONTROL LEVEL | RELEASE STAMP | CONTRACT NO. | | |
|---|---|---|---|---|
| | | DFTR. DFH | | 12-08-00 |
| | | CHKR. J PLESCIA | | 12-22-00 |
| | | LYT. | | |
| MODEL LEVEL | | ENGR. D F HAAS | | 12-08-00 |
| LAYOUT | | ME | | |
| NHA | | PLOT DATE | | 03-30-01 |
| MODEL | | PLOT SCALE | | 1=48 |
| CADDS IDENT. 59731M001 | | CUSTOMER | | |

PETERSON POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

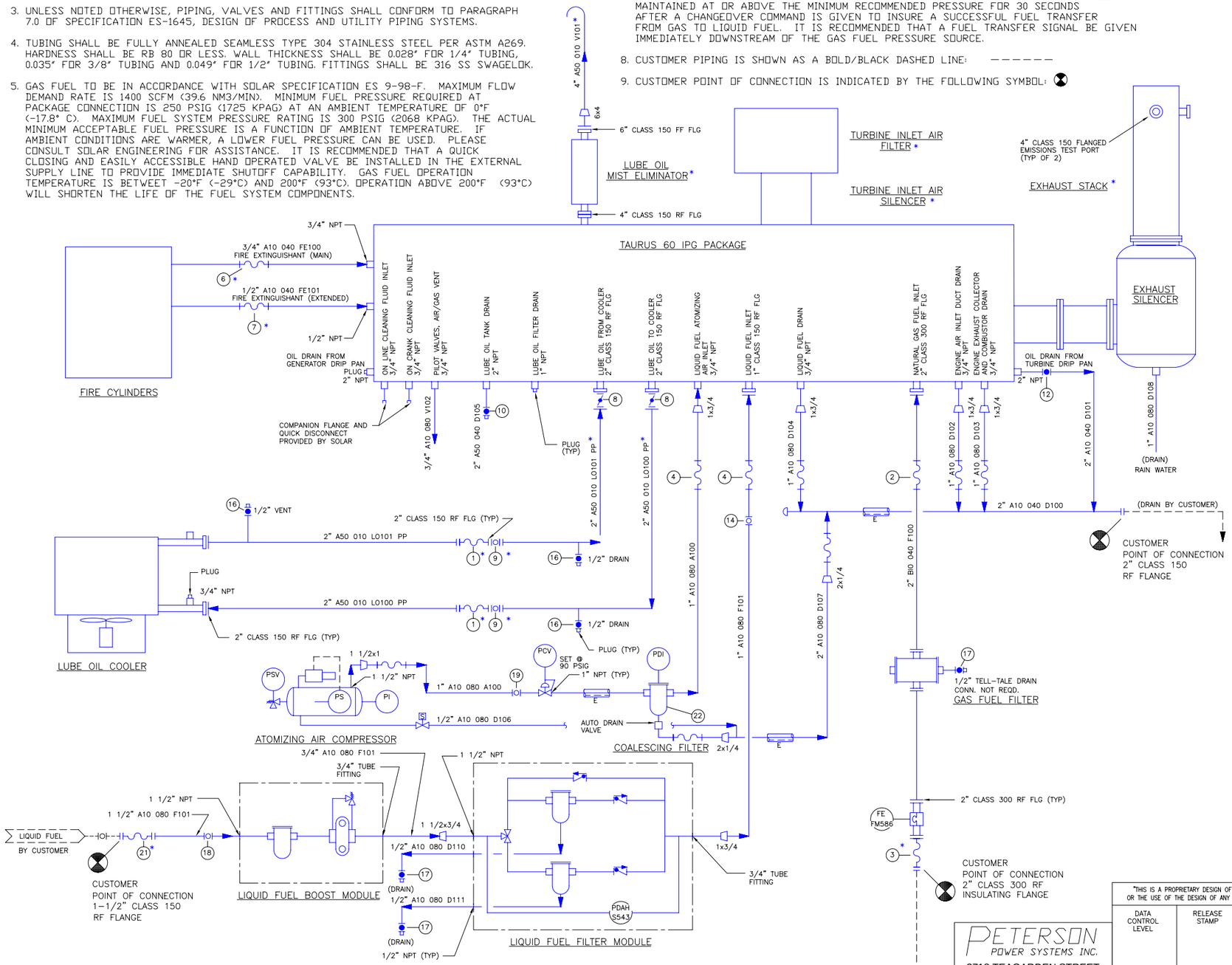
Solar Turbines — A Caterpillar Company
P.O. Box 85376
San Diego, California
92186-5376

EQUIPMENT ARRANGEMENT PLANS AND SECTIONS
TAURUS 60 – DUAL FUEL
MOBILE UNIT

| SIZE | CAGE NO. | DWG. NO. |
|---|---|---|
| D | | 59731-1500-M001 |
| SCALE: NOTED | TOTAL WT. | SHEET OF |

NOTES:

1. EQUIPMENT NOTED WITH AN ASTERISK (*) IS PROVIDED BY SOLAR, INSTALLED IN THE FIELD.
2. PIPING MATERIALS ARE IDENTIFIED PER SOLAR TURBINE'S LINE NUMBERING SYSTEM PER PARAGRAPH 6.0 OF THE SPECIFICATION ES-1645, DESIGN OF PROCESS AND UTILITY PIPING SYSTEMS.
3. UNLESS NOTED OTHERWISE, PIPING, VALVES AND FITTINGS SHALL CONFORM TO PARAGRAPH 7.0 OF SPECIFICATION ES-1645, DESIGN OF PROCESS AND UTILITY PIPING SYSTEMS.
4. TUBING SHALL BE FULLY ANNEALED SEAMLESS TYPE 304 STAINLESS STEEL PER ASTM A269. HARDNESS SHALL BE RB 80 OR LESS. WALL THICKNESS SHALL BE 0.028" FOR 1/4" TUBING, 0.035" FOR 3/8" TUBING AND 0.049" FOR 1/2" TUBING. FITTINGS SHALL BE 316 SS SWAGELOK.
5. GAS FUEL TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES 9-98-F. MAXIMUM FLOW DEMAND RATE IS 1400 SCFM (39.6 NM3/MIN). MINIMUM FUEL PRESSURE REQUIRED AT PACKAGE CONNECTION IS 250 PSIG (1725 KPAG) AT AN AMBIENT TEMPERATURE OF 0°F (-17.8° C). MAXIMUM FUEL SYSTEM PRESSURE RATING IS 300 PSIG (2068 KPAG). THE ACTUAL MINIMUM ACCEPTABLE FUEL PRESSURE IS A FUNCTION OF AMBIENT TEMPERATURE. IF AMBIENT CONDITIONS ARE WARMER, A LOWER FUEL PRESSURE CAN BE USED. PLEASE CONSULT SOLAR ENGINEERING FOR ASSISTANCE. IT IS RECOMMENDED THAT A QUICK CLOSING AND EASILY ACCESSIBLE HAND OPERATED VALVE BE INSTALLED IN THE EXTERNAL SUPPLY LINE TO PROVIDE IMMEDIATE SHUTOFF CAPABILITY. GAS FUEL OPERATION TEMPERATURE IS BETWEET -20°F (-29°C) AND 200°F (93°C). OPERATION ABOVE 200°F (93°C) WILL SHORTEN THE LIFE OF THE FUEL SYSTEM COMPONENTS.
6. LIQUID FUEL IS TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES 9-98. MAXIMUM LIQUID FUELFLOW DEMAND IS 8.0 GPM (30.3 LITERS/MIN). FUEL SUPPLY PRESSURE AT PACKAGE CONNECTION MUST BE REGULATED BETWEEN 20' (6096 MM) WET SUCTION LIFT TO 25 PSIG (171.7 KPAG).MAXIMUM ALLOWABLE LIQUID FUEL TEMPERATURE IS 140°F (60°C).
7. ON DUAL FUEL UNITS, THE GAS FUEL PRESSURE AT THE PACKAGE CONNECTION MUST BE MAINTAINED AT OR ABOVE THE MINIMUM RECOMMENDED PRESSURE FOR 30 SECONDS AFTER A CHANGEOVER COMMAND IS GIVEN TO INSURE A SUCCESSFUL FUEL TRANSFER FROM GAS TO LIQUID FUEL. IT IS RECOMMENDED THAT A FUEL TRANSFER SIGNAL BE GIVEN IMMEDIATELY DOWNSTREAM OF THE GAS FUEL PRESSURE SOURCE.
8. CUSTOMER PIPING IS SHOWN AS A BOLD/BLACK DASHED LINE: – – – – – –
9. CUSTOMER POINT OF CONNECTION IS INDICATED BY THE FOLLOWING SYMBOL:




PIPING & INSTRUMENTATION DIAGRAM

SCALE: NONE

| REVISIONS | | | | |
|---|---|---|---|---|
| ZONE | LTR. | DESCRIPTION 03-30-01 DFH | DATE | APPROVED |
| | A | ISSUED FOR REVIEW | 12-22-00 | DFH |
| | B | RECORD DRAWING | 03-30-01 | DFH |
| | C | NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY. | 1-15-03 | GH |

## BILL OF MATERIAL

| MARK | QTY | DESCRIPTION |
|---|---|---|
| 1 | 2 | LUBE OIL FLEXIBLE HOSE, GOODYEAR SUPER BLACK FLEXWING HIGH PRESSURE PETROLEUM TRANSFER HOSE, SYNTHETIC RUBBER (ORS) TUBE AND COVER WITH SYNTHETIC FABRIC AND WIRE REINFORCEMENT, 2" ID, 2.74" OD, 35 FEET LONG, RATED AT 250 PSIG AT 200 DEG F. PROVIDE 2" CLASS 150 LAP JOINT FLANGES WITH 90 DEG ELBOWS AT EACH END. SEE DETAIL 1, SHEET P002. ALL WETTED METAL SURFACES SHALL BE 304 SS. |
| 2 | 1 | FUEL GAS FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE, 2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 2" SCHEDULE 40 CARBON STEEL BUTT WELD ENDS, 12 1/2" LIVE HOSE LENGTH, 18" OVERALL HOSE LENGTH, 740 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 3 | 1 | FUEL GAS FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 2" CARBON STEEL SCH 40 CLASS 300 RF FLANGE ON ONE END WITH A 2" CARBON STEEL SCH 40 CLASS 300 FLOATING FLANGE ON THE OTHER END, 11 3/8" LIVE HOSE LENGTH, 18" OVERALL LENGTH, 740 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 4 | 2 | LIQUID FUEL AND AIR FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 1" CARBON STEEL FEMALE UNION ON THE OTHER END, 8" LIVE HOSE LENGTH, 14" OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 5 | | NOT USED |
| 6 | 1 | FIRE EXTINGUISHANT ($CO_2$) FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 3/4" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 3/4" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 3/4" CARBON STEEL FEMALE UNION ON THE OTHER END, " LIVE HOSE LENGTH, " OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 7 | 1 | FIRE EXTINGUISHANT ($CO_2$) FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1/2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1/2" CARBON STEEL SCH 40 MALE NPT NIPPLE CONNECTION ON ONE END WITH A 1/2" CARBON STEEL FEMALE UNION ON THE OTHER END, " LIVE HOSE LENGTH, " OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 8 | 2 | 2" LUBE OIL CLASS 150 LUGGED BUTTERFLY VALVE SHALL BE MILWAUKEE ML234V, DUCTILE IRON BODY, 316 STAINLESS STEEL DISC, VITON SEAT, LEVER HANDLE, LUGGED BODY STYLE FOR DEAD END SERVICE. |
| 9 | 2 | 2" LUBE OIL BALL VALVE, 316 STAINLESS STEEL BODY, BALL AND TRIM, FLOATING OR TRUNNION MOUNTED BALL, API-607 FIRE SAFE DESIGN, LEVER OPERATED, STANDARD BORE, CLASS 150 FLANGED ENDS, NELES-JAMESBURY SERIES 5000, 5150-31-3636TT OR EQUAL. |
| 10 | 1 | 2" LUBE OIL TANK DRAIN BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL. |
| 11 | | NOT USED |
| 12 | 1 | 2" TURBINE DRIP PAN BALL VALVE, BRASS BODY, 316 STAINLESS STEEL BALL AND TRIM, TFE SEATS, 2-PIECE BODY, LEVER OPERATED, STANDARD BORE, NELES-JAMESBURY SERIES 300, FIGURE 346 OR EQUAL. |
| 13 | | NOT USED |
| 14 | 1 | 1" LIQUID FUEL BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 3-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 4000, 4B-2236TT OR EQUAL. |
| 15 | | NOT USED |
| 16 | 3 | 1/2" LUBE OIL VENT BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL. |
| 17 | 3 | 1/2" LIQUID AND GAS FUEL DRAIN BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 2-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 6F, 6F-2236TT OR EQUAL. |
| 18 | 1 | 1 1/2" LIQUID FUEL BALL VALVE, CARBON STEEL BODY, 316 STAINLESS STEEL BALL AND TRIM, 3-PIECE BODY, API-607 FIRE SAFE DESIGN, LEVER OPERATED, FULL BORE, THREADED ENDS, NELES-JAMESBURY SERIES 4000, 4B-2236TT OR EQUAL. |
| 19 | 1 | 1" ATOMIZING AIR BALL VALVE, BRASS BODY, BRASS BALL AND TRIM, TFE SEATS, 2-PIECE BODY, AUTOMATIC DOWNSTREAM VENTING WHEN VALVE IS CLOSED, LEVER OPERATED, STANDARD BORE, THREADED ENDS, NELES-JAMESBURY SERIES 371 OR EQUAL. |
| 20 | | NOT USED |
| 21 | 1 | LIQUID FUEL FLEXIBLE METAL HOSE, SINGLE BRAID CORRUGATED METAL HOSE 1 1/2" ID 321 STAINLESS STEEL ANNULAR INNER CORE, 304L STAINLESS STEEL BRAID, 1 1/2" CARBON STEEL SCH 80 CLASS 150 RF FLANGE ON ONE END WITH A 1 1/2" CARBON STEEL SCH 80 CLASS 150 FLOATING FLANGE ON THE OTHER END, 12 1/4" LIVE HOSE LENGTH, 18" OVERALL LENGTH, 285 PSIG DESIGN PRESSURE AT 100 DEG. F. |
| 22 | 1 | ATOMIZING AIR COALESCING FILTER, ALUMINUM BODY WITH 1" NPT CONNECTIONS, DIFFERENTIAL PRESSURE INDICATOR, AUTOMATIC DRAIN VALVE, BLEED VALVE, 1 MICRON ELEMENT, RATED 170 SCFM AT 100 PSIG, SULLAIR MODEL MPF-170N. |

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DATA CONTROL LEVEL | RELEASE STAMP

CONTRACT NO.

| | | |
|---|---|---|
| DFTR. | DFH | 11-30-00 |
| CHKR. | J PLESCIA | 12-22-00 |
| LYT. | | |
| ENGR. | D.F. HAAS | 11-30-00 |
| ME | | |
| NHA | | |
| PLOT DATE | | 03-30-01 |
| PLOT SCALE | | 1=1 |
| CUSTOMER | | |

MODEL LEVEL
LAYOUT
MODEL
CADDS IDENT. 59731F002

PETERSON POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

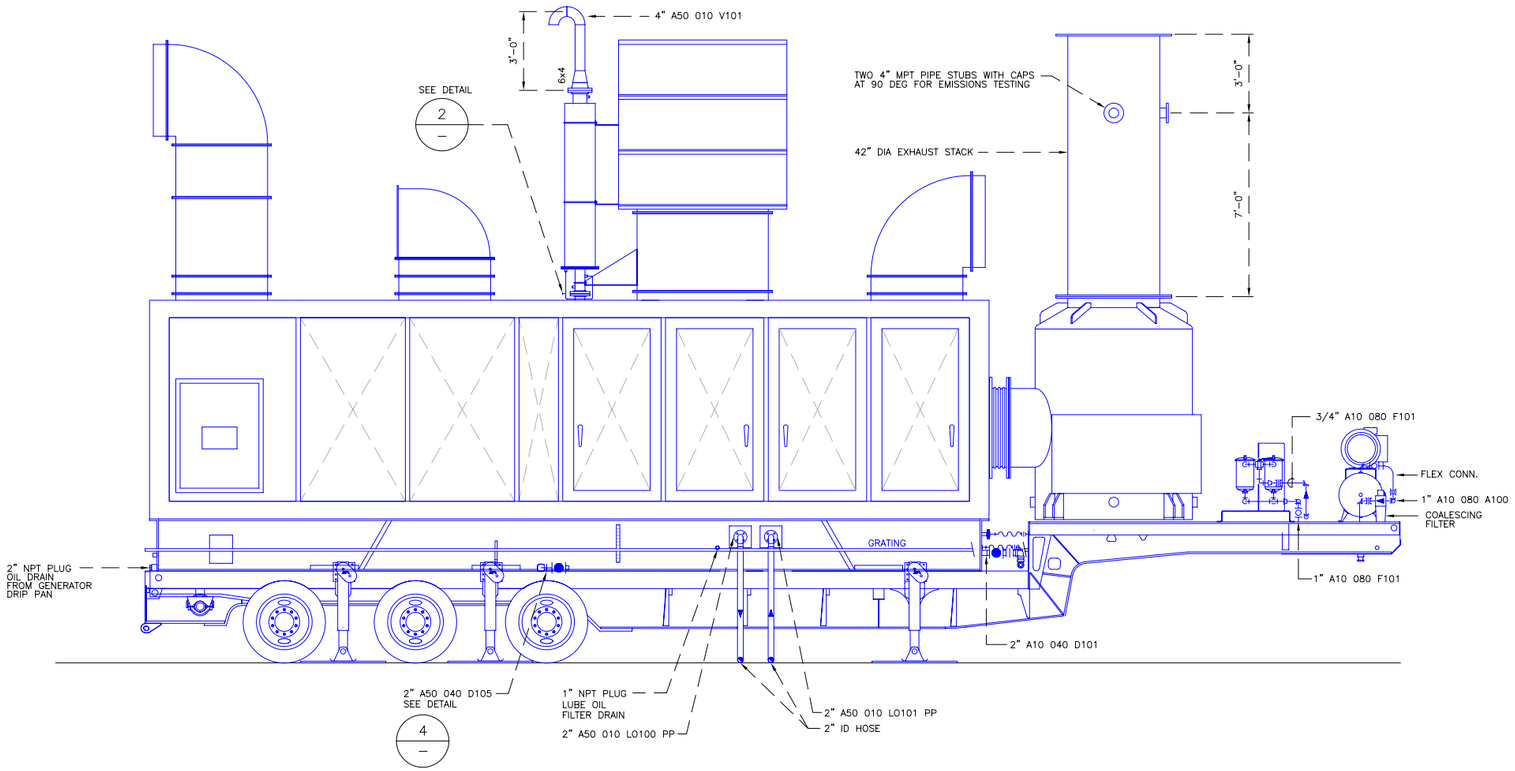
Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California
92186-5376

PIPING & INSTRUMENTATION DIAGRAM
TAURUS 60 – DUAL FUEL
MOBILE UNIT

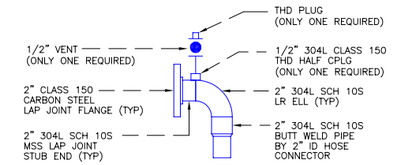
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SCALE: NONE | TOTAL WT. | SHEET OF

DWG. NO. 59731-1500-P002 SH. REV.

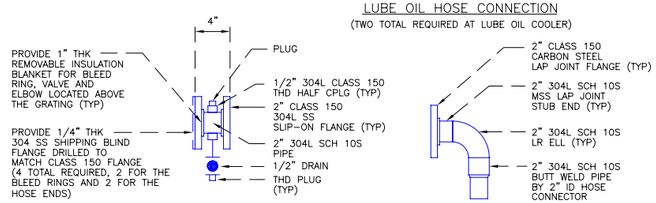
| ZONE | LTR. | DESCRIPTION | DATE | APPROVED |
|---|---|---|---|---|
| | A | ISSUED FOR REVIEW | 12-22-00 | DFH |
| | B | RECORD DRAWING | 03-30-01 | DFH |
| | C | ROTATED GENERATOR EXHAUST ELBOW SILENCER | 05-22-01 | DFH |
| | D | NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY | 1-15-03 | GH |




PIPING SECTION — D P001
SCALE: 3/8" = 1'-0"



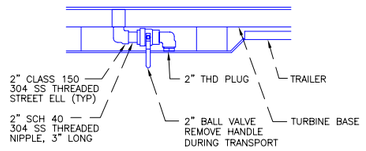

LUBE OIL HOSE CONNECTION
(TWO TOTAL REQUIRED AT LUBE OIL COOLER)



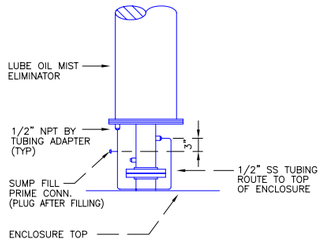

BLEED RING AT TURBINE
(TWO TOTAL REQUIRED)

LUBE OIL HOSE CONNECTION
(TWO TOTAL REQUIRED AT TURBINE)

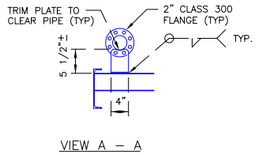
DETAIL — LUBE OIL PIPING — 1 P001
SCALE: 1 1/2" = 1'-0"



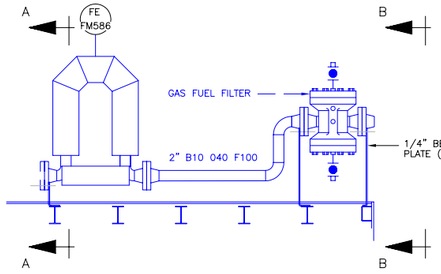

DETAIL — LUBE OIL TANK DRAIN — 4 —
SCALE: 3/4" = 1'-0"

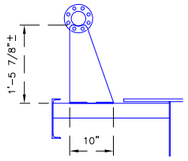



DETAIL — PRIME CONN. — 2 —
SCALE: 3/4" = 1'-0"




VIEW A — A




VIEW B — B

DETAIL — PIPE SUPPORT — 3 P001
SCALE: 3/4" = 1'-0"

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PETERSON
POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

| | | | |
|---|---|---|---|
| DATA CONTROL LEVEL | RELEASE STAMP | CONTRACT NO. | |
| | | DFTR. DFH | 12-12-00 |
| | | CHKR. J PLESCIA | 12-22-00 |
| | | LYT. | |
| MODEL LEVEL | | ENGR. D F HAAS | 12-12-00 |
| LAYOUT | | ME | |
| NHA | | PLOT DATE | 03-30-01 |
| MODEL | | PLOT SCALE | 1=32 |
| CADDS IDENT. 59731P002 | | CUSTOMER | |

Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California
92186-5376

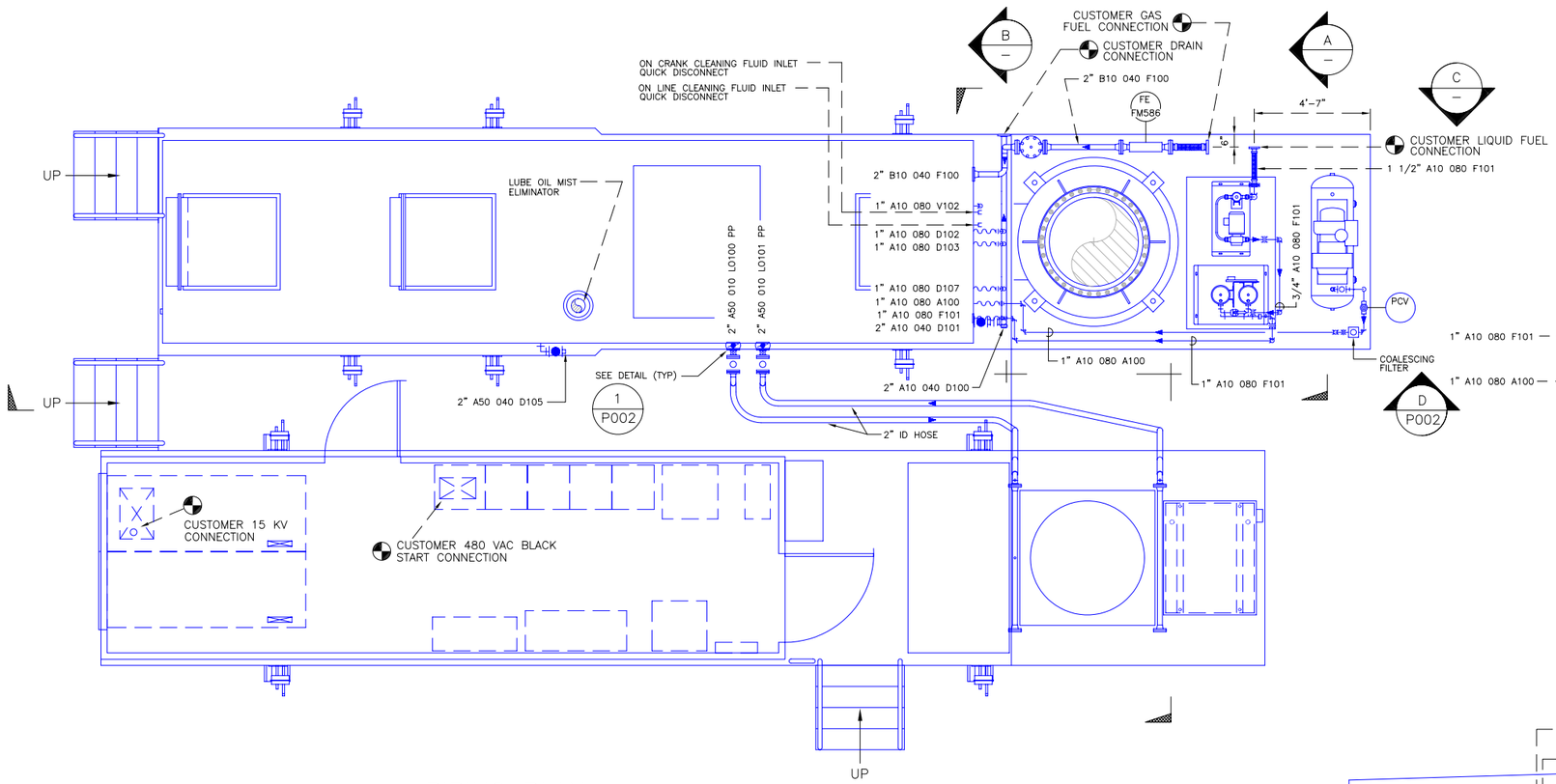
PIPING SECTION & DETAILS
TAURUS 60 — DUAL FUEL
MOBILE UNIT

| SIZE | CAGE NO. | DWG. NO. |
|---|---|---|
| D | | 59731-1500-P002 |
| SCALE: NOTED | TOTAL WT. | SHEET OF |

DWG. NO. 59731-1500-P002 SH. REV.

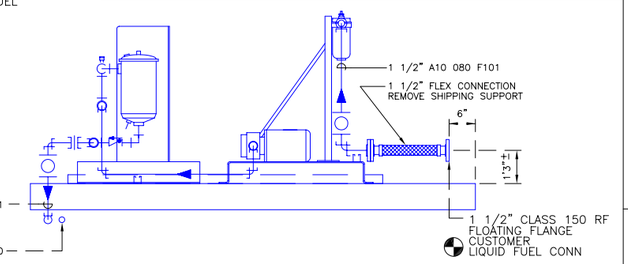
REVISIONS

| ZONE | LTR. | DESCRIPTION | DATE | APPROVED |
|---|---|---|---|---|
| | A | ISSUED FOR REVIEW | 12-22-00 | DFH |
| | B | RECORD DRAWING | 03-30-01 | DFH |
| | C | ROTATED GENERATOR EXHAUST ELBOW SILENCER | 05-22-01 | DFH |
| | D | NOTES & DIMENSIONS ADDED BY PETERSON POWER SYSTEMS TO IMPROVE CLARITY | 1-15-03 | GH |




PIPING PLAN

SCALE: 3/8" = 1'-0"



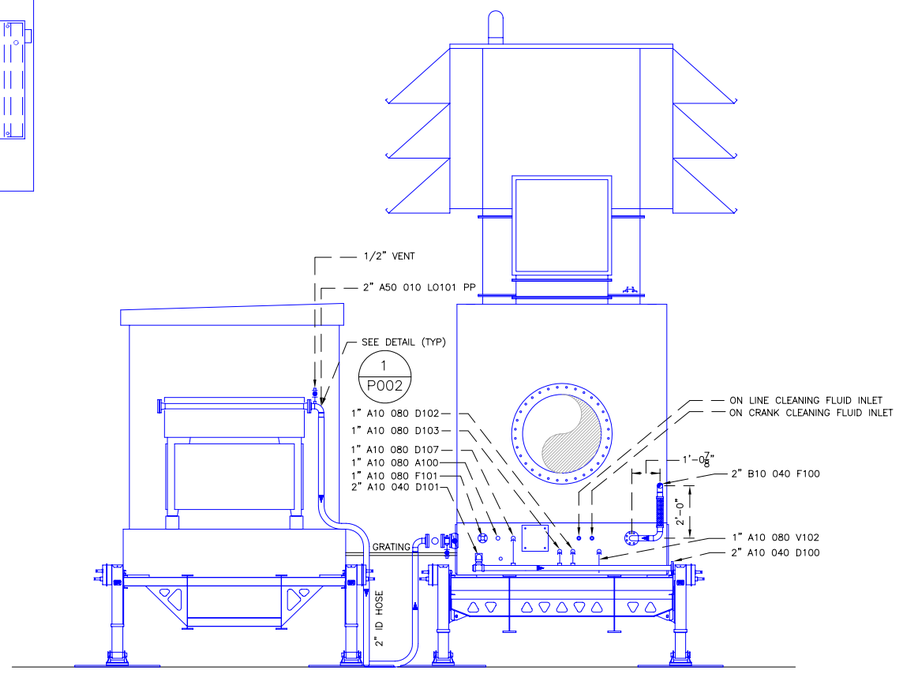

PIPING SECTION

SCALE: 3/4" = 1'-0"




PIPING SECTION

SCALE: 3/8" = 1'-0"




PIPING SECTION

SCALE: 3/8" = 1'-0"

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PETERSON
POWER SYSTEMS INC.
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577

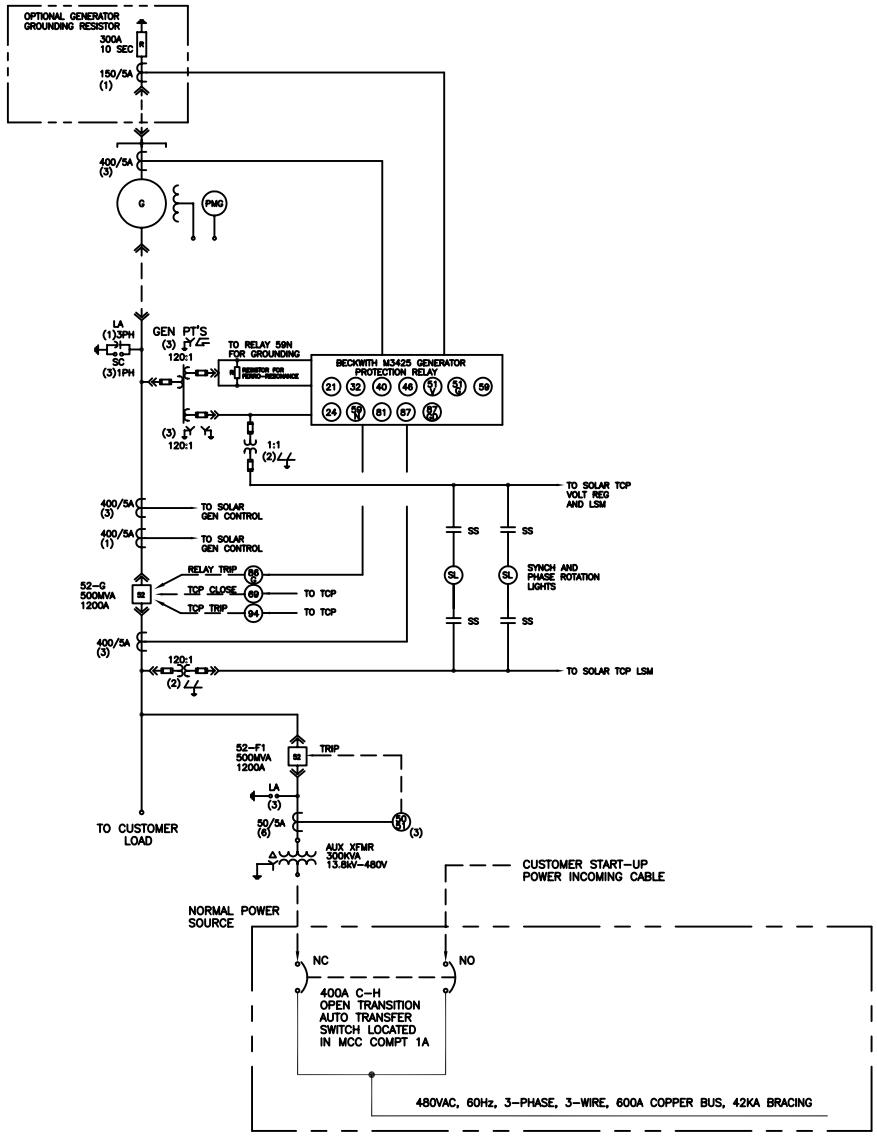
PID Engineering
Power and Industrial Design Corporation
9625 BLACK MOUNTAIN ROAD SUITE 308
SAN DIEGO, CA 92126 PHONE: (858) 348-3200

| | | | |
|---|---|---|---|
| DATA CONTROL LEVEL | RELEASE STAMP | CONTRACT NO. | |
| | | DFTR. DFH | 12-12-00 |
| | | CHKR. J PLESCIA | 12-22-00 |
| | | LYT. | |
| MODEL LEVEL | | ENGR. D F HAAS | 12-12-00 |
| LAYOUT | | ME | |
| NHA | | PLOT DATE | 03-30-01 |
| MODEL | | PLOT SCALE | 1=32 |
| CADDS IDENT. 59731P001 | | CUSTOMER | |

Solar Turbines
A Caterpillar Company
P.O. Box 85376
San Diego, California
92186-5376

PIPING PLAN AND SECTIONS
TAURUS 60 - DUAL FUEL
MOBILE UNIT

| SIZE | CAGE NO. | DWG. NO. |
|---|---|---|
| D | | 59731-1500-P001 |
| SCALE: NOTED | TOTAL WT. | SHEET OF |




REVISIONS

| REV | DESCRIPTION | DATE | APPR'D |
|---|---|---|---|
| A | ISSUED FOR APPROVAL | 10/30/00 | MJR |
| 0 | ISSUED FOR CONSTRUCTION | 11/14/00 | MJR |
| 1 | AS-SHIPPED | 5/3/01 | MJR |

REFERENCE DRAWINGS

NOTES

IPCS APPROVED

PROJ ENG DATE
DISCIPLINE ENG DATE
CHECK DATE
DESIGN/DRAFT DATE
PROJECT ITEM NO.
CUSTOMER IDENT. NO.
CUSTOMER SOLAR

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SOLAR TURBINES-CAT PROJECT
MOBILE POWER TRAILER PROJECT
OVERALL ONELINE DIAGRAM

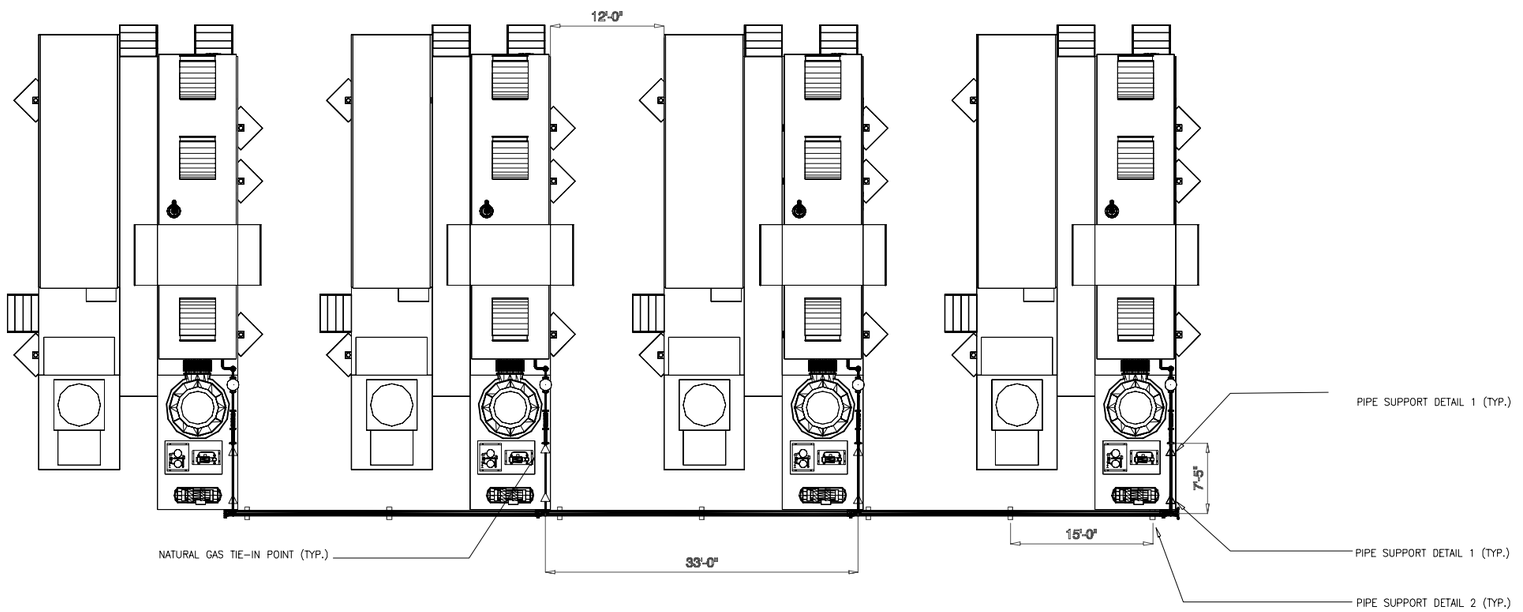
INDUSTRIAL POWER & CONTROL SYSTEMS
6606 HARVEY WILSON DRIVE HOUSTON, TX 77020

DRAWING NO. J20020-E001
SCALE
REV. 1
SHEET

PROJECT: CAT PROJECT FILE NAME:

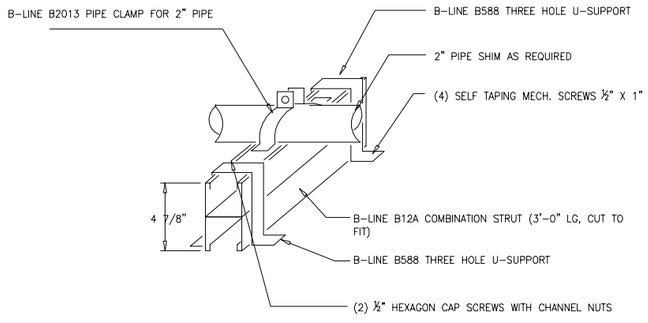
## NOTES:

1. SEE M-402 FOR ISOMETRIC VIEW AND BILL OF MATERIALS.
2. SEE G-001 GENERAL NOTES FOR INSTALLATION.
3. GAS FUEL TO BE IN ACCORDANCE WITH SOLAR SPECIFICATION ES-9-98-F.
4. MAXIMUM FLOW DEMAND PER UNIT IS 1400 SCFM OR 5600 SCFM FOR 4 UNITS.
5. MINIMUM FUEL SYSTEM REQUIRED AT PACKAGE IS 250 PSIG AT AMBIENT TEMPERATURE OF 0°F.
6. SEE E-204 AND E-205 DRAWINGS FOR ELECTRICAL LAYOUT.



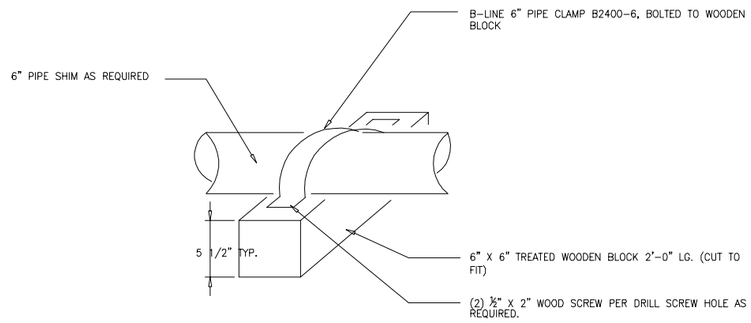

## (4) UNIT XQ5200 PLAN

SCALE = 1/8" : 1'-0" - SF:96
0 1 2 4 8




## 1 PIPING SUPPORT DETAILS

8 ASSEMBLIES




## 2 PIPING SUPPORT DETAILS

7 ASSEMBLIES

PROGRESS PRINT
NOT FOR CONSTRUCTION

PETERSON POWER SYSTEMS
2718 TEAGARDEN STREET
SAN LEANDRO, CA 94577
PH: (800) 889-WRMS
Fax: (925) 933-5167
CRITICAL ENGINEERING
Walnut Creek, CA
Seattle, WA

| Rev. | Description | Date | Drawn By | Appr. By |
|---|---|---|---|---|

| | |
|---|---|
| Drawn By: FDA | XQ5200 STANDARD ARRANGEMENT 4 UNITS -20MW |
| Designed By: TH | PLAN VIEW AND PIPE SUPPORT NATURAL GAS |
| Date: 12.02.04 | One Inch at Full Scale (0 .5 1.0) / Dwg. No: M-202 / Rev.: A |
| Proj. No.: 04-284 | |




# PROACTIVE POWER . . . FAST

## Cat dealer provides Canadian government a turnkey power project, including 115 MW of peaking power, in just six weeks.

The word impressive just doesn't seem to cut it when trying to describe Toromont Power Systems' latest mega power project.

The Cat dealer, with the help of Cat Rental Power and Peterson Power Systems, the Northern California Dealer responsible for world wide marketing of mobile turbines, provided 115 MW of peaking power to the Ontario Provincial Government. That in itself is an impressive job. But to install it and have it all online in a mere six weeks is phenomenal.

"The Ontario Independent Electricity Market Operator (IEMO) is the group that looks after the electrical system. They were forecasting a power shortage potential through summer and fall," explains Peter Ronson, account manager for Toromont. The province very nearly implemented rolling blackouts during the summer of 2002, so there was a lot of concern for the summer of 2003.

"We put the idea in front of the government that on short notice, they could bring in significant amounts of temporary generation to use during peak power periods," Ronson notes.

The government took Toromont up on their offer and sent out a request for proposal for 200 to 400 MW of peak generation. When all was said and done, out of the original seven companies awarded contracts for about 450 MW, only three companies came through for approximately 250 MW of natural-gas-fueled peaking power. Cat dealer Toromont was awarded the largest share at 115 MW. The contract gave the suppliers only six weeks to put all the capacity online.

### TURNKEY FROM DAY ONE

"Our single biggest challenge was simply the logistics of the project," explains Ronson. "Because this was a turnkey project, we provided not only the generation (32 Cat power modules and turbines), but also all the distribution equipment, transformers, high-voltage disconnects, natural gas piping, valves, regulators, meters, etc., to complete the project. We were engineering, procuring, shipping, installing and commissioning all at the same time, while keeping our regular day-to-day business going.

"At the same time, Toromont was responsible for all emission and noise approvals, permits and contracts with land owners and utilities. "I spent much of my time trying to keep contracts and other needed paperwork from holding up our engineering and construction personnel, "exclaims Ronson.

But before any of that could even begin, appropriate sites for the equipment had to be identified. "Our customer wanted a complete turnkey project," explains Ronson. "That meant they looked to us to identify not only the equipment, but also where to hook it up as well ashow to hook it up — and then operate it for the duration of the contract. "Toromont identified three sites for the temporary generation:

1. Markham — This is the largest site and is located adjacent to a local utility-owned transformer station. The step-down transformer station has the capacity to house 100 additional MW. It also has a high-pressure natural-gas line (crucial as the government accepted only natural-gas-fueled generation). It's here that Toromont placed 19 Cat XQ5200 mobile power modules

powered by Solar Taurus 60 Turbines (The 5.2 MW Turbines were made available by Peterson Power Systems.)

2. Bear Road Landfill — This site is an existing landfill gas power plant with four Cat G3516 engines and a natural-gas line for fuel blending. “It met our two biggest requirements — an electrical connection with existing parallel generation protection equipment and natural-gas connection point,” Ronson notes. Six XQ1250G power modules are located here. Each is powered by a Cat G3516B engine and is rated at 1,250 kW continuous.

3. Concord — This site is Toromont’s main head-office location. Seven XQ1250G power modules were installed here.

## ADDRESSING THE CHALLENGES

Sheer numbers were the theme for this project. For example, at times, there were more than 100 people working at just one of the three installation sites.

Challenges were plentiful, but so were solutions. “Once we began construction, locating Cat generator sets and turbines was the easiest part, thanks to the Cat dealer network,” says Ronson. Especially with the help from Gene Hamilton, Mobile Turbine Specialist at Peterson Power Systems. “We were ready as soon as they called to work on the technical aspects of the proposal,” says Hamilton. “It is really great when the CATERPILLAR Network mobilizes to get the job done.” Sourcing materials was the most challenging and risky. Because most of the generation came from the United States, a difference in standard voltage had to be addressed. Cat XQ1250s run at 480 volts in the U.S., but in Canada the standard voltage at that level is 600 volts. The Solar Turbines generate at 13,800 volts in the U.S.; standard distribution level voltage in Ontario is 27, 600 volts.

“Finding enough step-up transformers became an issue. We ended up contracting out for custom-made, brand-new transformers,” says Ronson.

All brand-new cable and suitably sized high-voltage disconnects also had to be sourced. “Materials and logistics played a huge roll in this project,” he adds. “And coordination, teamwork and a lot of long hours and hard work were the key to it all.” The dealer had cooperation from contractors, the local electrical utilities, the gas company, as well as the Ontario Ministry of Environment (for air and noise emissions permits).

Toromont’s Electric Power Field Service staff took on the job of commissioning all the Cat XQ1250 packages, while a team of Solar Turbine technicians from Peterson Power Systems worked tirelessly at commissioning two turbines a day – a job that normally takes three days per turbine.



*Remote start-up, shutdown and monitoring is handled by Point guard, a caterpillar affiliate company, and requires no site-staffed technician.*




*The province of Ontario peaks at around 26,000 MW. This project’s 115 MW may not seem like a drop in the bucket, but when energy is stretched, it could make a huge difference.*

## FOLLOWING THROUGH

With the sheer effort and determination of a lot of folks, the 115-MW Ontario project was completed on time. As of this writing, the last generator was brought online and successfully tested.

The contract details that the customer can call the dealer anytime weekdays between 7 a.m. and 11 p.m. to provide generation. Within 15 minutes, all 23 units must be online. “There are significant financial penalties if the generation doesn’t perform, ”explains Ronson.

To assure that penalties aren’t incurred, and to address the need to immediately and remotely start all of the equipment, Toromont turned to PointGuard, a Caterpillar affiliate company, to provide system monitoring and management solutions. PointGuard remotely starts, stops and monitors the generation.

Before they can bring the units to full load, the PointGuard staff has to obtain permission from the utilities. “It’s a tough job, but we’re confident they will perform it to a tee,” Ronson concludes.

The dealer will complete weekly testing and preventive maintenance with in-house field service staff. The rental is scheduled to continue until at least the end of the year.

The temporary generators have already proved themselves very useful during the August cascading blackout in cities across the Midwest and Northeast United States, as well as the Canadian province of Ontario.

“As soon as the power was restored to the main transformer stations where the generators are connected, we started them up and supplied power on a continuous 24/7 basis for several days until the nuclear power plants in Ontario could be brought back online,” Ronson says. “It was unfortunate that we could not provide emergency power immediately during the blackout, but the sites are simply not technically setup to do so. However, if the blackout had continued longer than 12 hours at our sites, we would have definitely made the needed changes to provide emergency power.

“Would you believe that the very same afternoon of the blackout, we were providing a tour of the sites to a number of the provincial government representatives, the IEMO, utility reps and others?” he reveals. “It just goes to show that proactive power planning really does pay off.”

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# GENERATOR DATA SHEET

**EE - 3194**

## Manufacture Data

| | |
|---|---|
| Model | SAB |
| Frame No. | 21320-32 |

## Generator Rating

| | | | | | |
|---|---|---|---|---|---|
| KW | 5300 | KVA | 6625 | P.F. | 0.8 |
| Voltage (Line) | 13800 | (Phase) | 7967 | | |
| Amps (Line) | 277 | (Phase) | 277 | | |
| Phase | 3 | Poles | 4 | Connection | Wye |
| Hertz | 60 | RPM | 1800 | Pitch (P.U.) | 0.788 |

Insulation Class F

Temperature Rise 80 °C (Stator by RTD)
80 °C (Field by Resistance)

## Exciter Rating

| | | | | | |
|---|---|---|---|---|---|
| KW | 21 | Volts | 125 | Amps | 168 |
| Field Resistance | 16.3 | Ohms at 25°C | | | |
| Temperature Rise | 80 | °C (Armature) | | | |
| | 80 | °C (Field) | | | |

## Excitation Requirements

| | Volts | Amps |
|---|---|---|
| Exciter Field | | |
| Generator No Load | 22 | 1.1 |
| Generator Full Load | 66 | 3.3 |
| 320% Fault Current Forcing | 200 | 10 |

## PMA Rating

| | | | | | |
|---|---|---|---|---|---|
| KVA | 2.4 | Volts | 240 | Amps | 10 |
| Hertz | 120 | Phase | 1 | | |
| Temperature Rise | 60 °C | | | | |

## Generator Operating Characteristics

Efficiency (%)

| Load | 0.80 P.F. | 1.0 P.F. |
|---|---|---|
| 100% | 96.6 | 97.1 |
| 75% | 96.4 | 96.8 |
| 50% | 95.6 | 95.9 |
| 25% | 92.8 | 92.9 |

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# GENERATOR DATA SHEET

**EE - 3194**

| Losses (KW) | Full Load | No Load |
|---|---|---|
| Core | 46.1 | 46.1 |
| Friction & Windage | 47.1 | 47.1 |
| Stray load | 31.3 | 0.0 |
| Stator I2R loss | 40.5 | 0.0 |
| Rotor I2R loss | 17.4 | 2.4 |
| Exciter | 2.0 | 0.3 |
| Total | 184.3 | 96.0 |

Reactances (per unit at KVA rating)

| | | Saturated | Unsaturated |
|---|---|---|---|
| Direct Axis Synchronous | Xd | 1.786 | 1.976 |
| Direct Axis Transient | X'd | 0.268 | 0.288 |
| Direct Axis Subtransient | X"d | 0.173 | 0.182 |
| Quadrature Axis Synchronous | Xq | 1.032 | 1.032 |
| Quadrature Axis Transient | X'q | 1.032 | 1.032 |
| Quadrature Axis Subtransient | X"q | 0.192 | 0.202 |
| Negative Sequence | X2 | 0.187 | 0.192 |
| Zero Sequence | Xo | 0.067 | 0.071 |

Time Constants

| | | |
|---|---|---|
| Direct Axis O.C. Transient | T'do | 5.540 |
| Direct Axis S.C. Transient | T'd | 0.751 |
| Direct Axis O.C. Subtransient | T"do | 0.050 |
| Direct Axis S.C. Subtransient | T"d | 0.032 |
| Armature Short Circuit | Ta | 0.082 |

Resistance at 25 °C

| | | | |
|---|---|---|---|
| DC Armature | Ra | 0.129 | ohms |
| DC Field | Rf | 0.891 | ohms |
| Positive Sequence | R1 | 0.006 | p.u. |
| Negative Sequence | R2 | 0.016 | p.u. |
| Zero Sequence | Ro | 0.007 | p.u. |

Short Circuit Ratio — SCR 0.560

Inertia Constant (Generator Only) — H 0.893 kW-sec/kVA

TIF (1960 weighting) — 50 Balanced — 40 Residual

Waveform Deviation Factor — 6% at no load

Harmonic Content — 3.0% Individual — 3.0% Total

Allowable Negative Sequence Current — 10% Continuous — Short Time K= 40

Guaranteed Noise Level (dBA at 1 meter) — 110

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# GENERATOR DATA SHEET

**EE - 3194**

| Initial Temperature Detector Settings | Alarm | Shutdown |
|---|---|---|
| Windings | 120 °C | 130 °C |
| Bearings | 185 °F | 190 °F |

| Heat Rejection at Rated Load (Btu / Hr) | |
|---|---|
| Exterior Surfaces of Generator | 1601 |
| Generator Exhaust | 627191 |

| Transient Torques | Max. Torque (Lb-Ft) | (per unit) |
|---|---|---|
| 3-Phase Short Circuit | 182422 | 8.80 |
| L-L Short Circuit | 184841 | 8.92 |
| 3-Phase Out of Phase With an Infinite Bus | 474298 | 22.89 |
| 1-Phase Out of Phase With an Infinite Bus | 490918 | 23.69 |

L-L Short Circuit Torque Equation (per unit of rated torque) w = 377.0 radians / sec

$$6.09e(-13.6)t \sin(wt - 0.16) - 3.59e(-2.7)t \sin(2wt - 0.07) + 0.73e(-17.2)t$$

| Short Circuit Current | RMS Symmetrical | Peak Asymmetrical |
|---|---|---|
| 3-Phase | 1.60 kA | 4.53 kA |
| L-L | 1.33 kA | 3.77 kA |
| L-N | Limited by Neutral Grounding Device | |

| Voltage Dip<br>Motor Starting (0.0 P.F.) | Voltage Dip | Inrush (SKVA) | Motor HP (Code F) |
|---|---|---|---|
| | 10% | 2747 | 490 |
| | 15% | 4362 | 779 |
| | 20% | 6180 | 1104 |
| | 25% | 8240 | 1471 |
| | 30% | 10594 | 1892 |

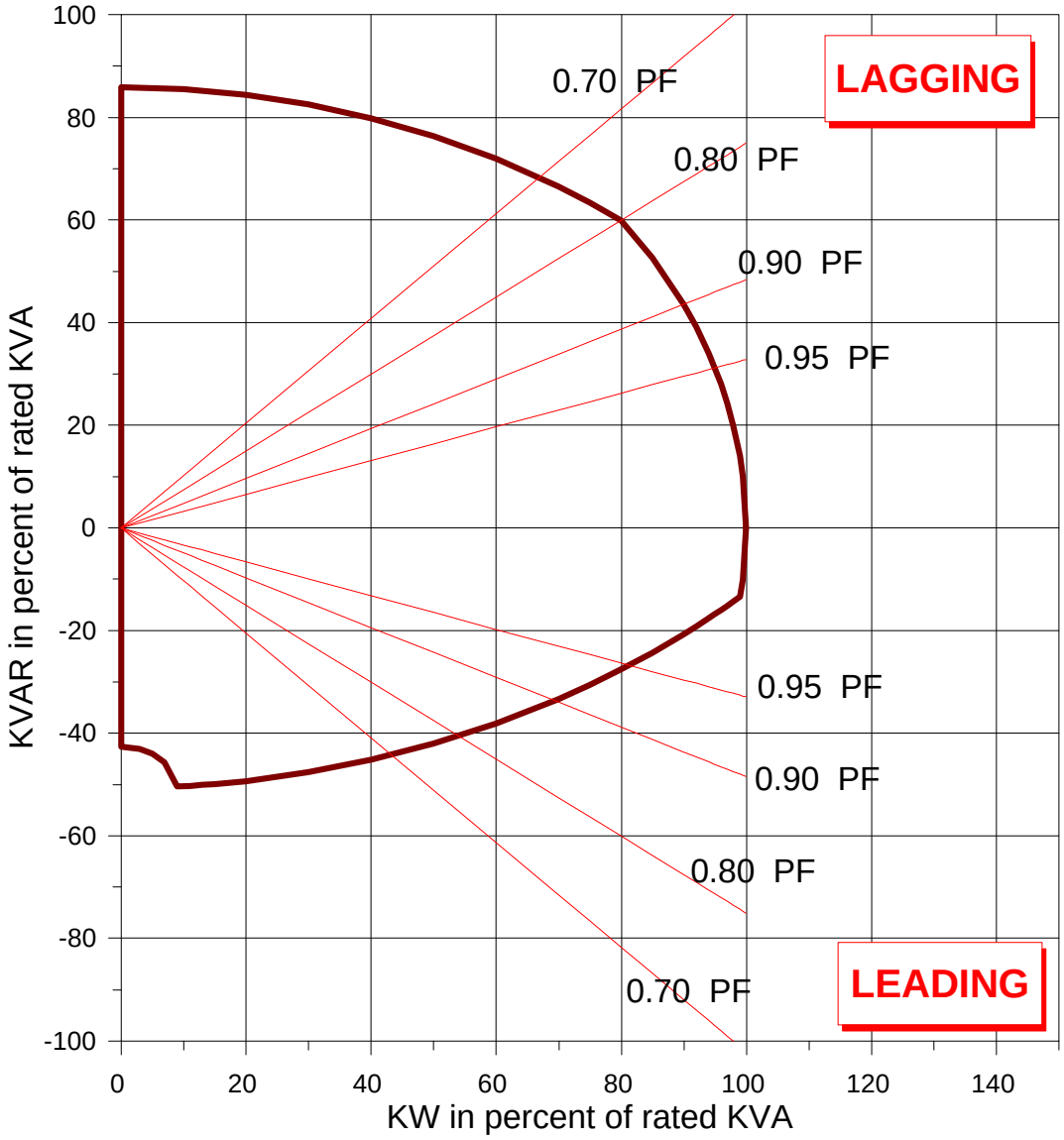
| Step Loads (0.80 P.F.) | Applied Load | Applied Load (KVA) | Voltage Dip |
|---|---|---|---|
| | 25% | 1656 | 4.0% |
| | 50% | 3313 | 7.9% |
| | 100% | 6625 | 15.3% |

**Voltage Regulator System Recommendations**

Manufacturer: Basler Electric Co. Model: SSR 125-12

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# REACTIVE CAPABILITY CURVE




Rating:

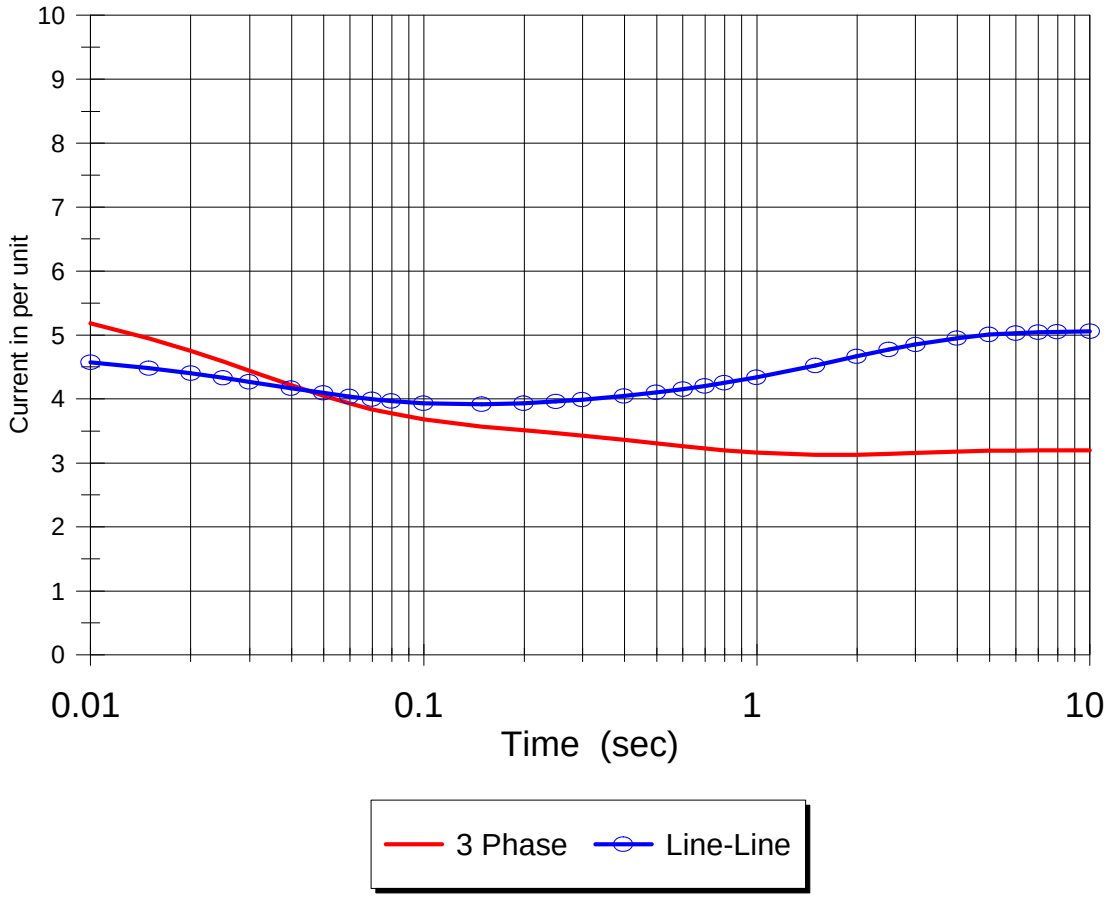
| | |
|---|---|
| 6625 | KVA |
| 13800 | Volts |
| 277 | Amps |
| 0.80 | P.F. |
| 1800 | RPM |

Class B Temperature Rise

**EE- 3194A**

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# SHORT CIRCUIT DECREMENT CURVES




Rating:

| | |
|---|---|
| 6625 | KVA |
| 13800 | Volts |
| 277 | Amps |
| 0.80 | P.F. |
| 1800 | RPM |

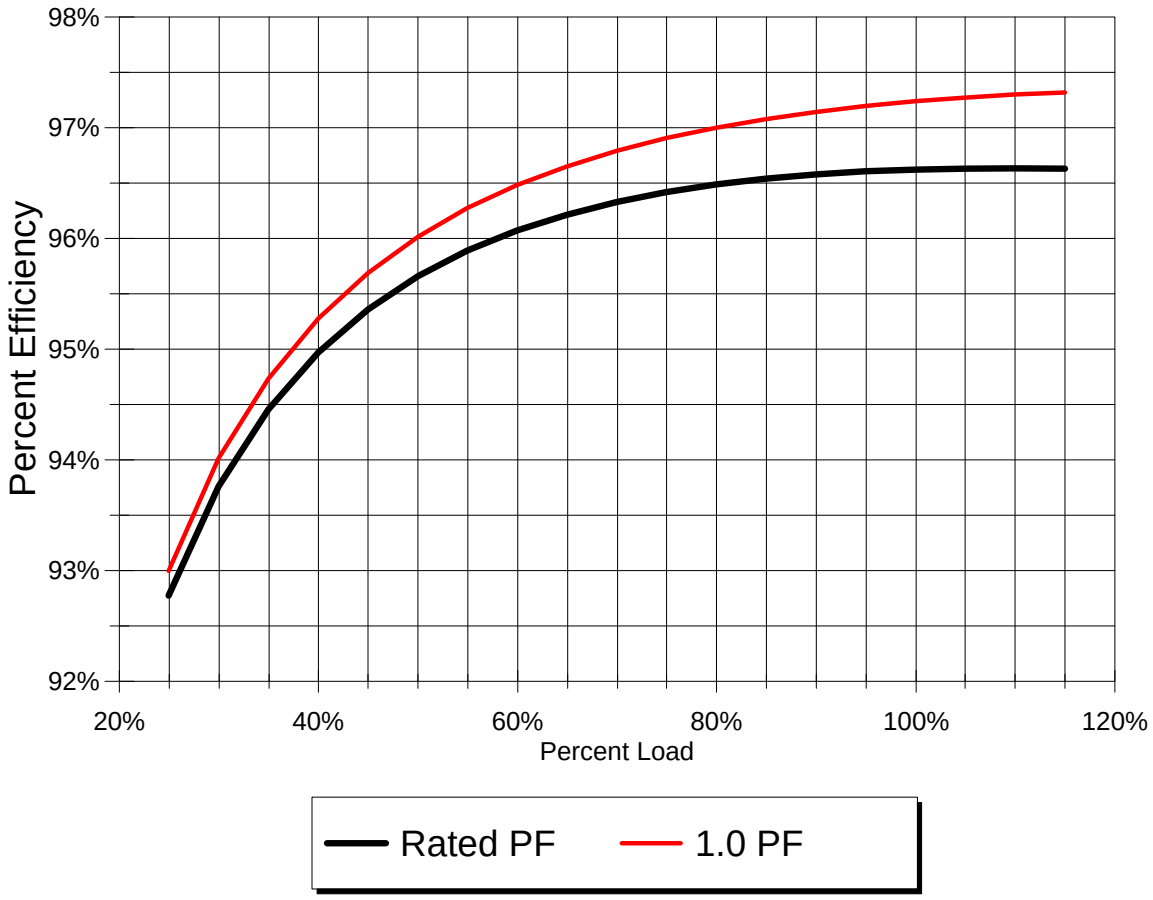
Class B Temperature Rise

**EE- 3194B**

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# EFFICIENCY CURVES




100% Load = 5300 kW

Rating:

6625 KVA
13800 Volts
277 Amps
0.80 P.F.
1800 RPM

Class B Temperature Rise

**EE- 3194C**

## Hearn, Bill G.

**From:** Hearn, Bill G.
**Sent:** December 12, 2007 9:58 AM
**To:** 'AndreaMacDonald@nlh.nl.ca'
**Cc:** King, Brian
**Subject:** FW: FT8 MobilePac

Andrea:

We received the following information (below) on the P&W FT8 MobilePac GT. While details need to be finalized, this is a start. Mr. Vecchiarelli noted that if Hydro has any interest in his offer, please let him know so he can firm up this offer. We will include words in the Final Report on the tentative P&W MobilePac offer and note that it is up to Hydro to contact P&W if you wish to pursue this matter. P&W has indicated the European customer requires the MobilePacs for winter operation only.

Bill

**Bill Hearn, P. Eng**
Senior Consultant -- Power
Stantec
#1 South 130 Eileen Stubbs Avenue
Dartmouth NS B3B 2C4
Ph: (902) 434-7331 Ext. 1371
Fx: (902) 462-1660
Bill.Hearn@stantec.com
www.stantec.com

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Please consider the environment before printing this email.

-----Original Message-----
From: King, Brian
Sent: December 12, 2007 9:37 AM
To: Hearn, Bill G.
Subject: FW: FT8 MobilePac

Bill,
Here is the offer by Pratt and Whitney for a 25MW Rental Unit. I have added numbers to the text to show how much it would cost for a four month rental to match what we said for the Caterpiller offer. Note that this is in the same ball-park figure as for the Cat offer-- $3,152,000.

Brian

-----Original Message-----
From: Vecchiarelli, Philip [mailto:philip.vecchiarelli@pw.utc.com]
Sent: Wednesday, December 12, 2007 12:51 AM
To: brianking@stantec.com
Cc: King, Brian; Rooks, Debbie L.
Subject: FT8 MobilePac

Brian:
Sorry this late on Tuesday but it has been a long day with e-mail problems.
The units that we are looking at to lease are owned by a European customer.
The units would have to be transported to your site in Canada. This is a

quick estimate of what the costs would be for a lease. **The customer has seven units that may be available for lease in the summer months.** If you have any interest, please let us know so we can firm up this offer.

| | | |
|---|---|---|
| Transportation to site $625,000 | | $ 625,000 |
| Monthly lease fee $400,000 | 4 Months | $1,600,000 |
| Site set up fee $150,000 per site | | $ 150,000 |
| Site dismantle fee $150,000 per site | | $ 150,000 |
| Transportation back to Europe $625,000 | | $ 625,000 |
| Full time site supervision per month $25,000. | 4 Months | $ 100,000 |
| HV Connection | | $ 50,000 |
| Fuel connection | | $ 7,500 |
| | **TOTAL:** | **$3,307,500** |

Phil Vecchiarelli
Area Director
PWPS
860-565-7877

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MOBILEPAC SERVICES »

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# MOBILEPAC™

## The FT8 MOBILEPAC is 25 megawatts of power on wheels.

Pratt & Whitney Power Systems' newest product, the FT8 MOBILEPAC, is a self-contained, gas turbine powered electric generating unit using PWPS' efficient FT8 gas turbine. This new mobile package consists of two primary units - the power trailer and the control trailer. The power trailer contains the gas turbine and the electric generator, while the control trailer houses the electrical control unit.

The MOBILEPAC can be on the grid and operating within 8 hours. This type of power package, along with its relatively small size, allows the MOBILEPAC to be installed in almost any location and conveniently relocated or combined with other units to meet an area's emergency or temporary power needs.

Modular options can be added to allow long-term environmentally compatible operation. Just like the proven FT8, the MOBILEPAC can run on either gas or liquid fuel. Black start capability is another option with the MOBILEPAC.

CA-NLH-52 Attachment 2, Page 480 of 614
Depreciation Methodology

# NEW STANDARD FOR MOBILE GAS TURBINE POWER PACKAGES

Presenter: Brian Donnelly
Chief Engineer
Pratt & Whitney Power Systems,
80 Lamberton Road
Windsor, CT 06095

## Introduction

There has been an increased need for large-scale transportable power to meet emergency, outage and climate driven requirements around the world. To address this need, engineers at Pratt & Whitney Power Systems set out to create a 25MW Mobile Power Plant readily transportable by air, sea, and land, easy to set up within a small footprint in potentially challenging environments, and environmentally compliant.

## Design

The primary design goal was to provide a transportable power plant that required minimum setup time and high reliability. Four trailers contain all of the equipment needed to set up a MOBILEPAC plant. One of two operational trailers contains the FT8 gas turbine engine aligned and coupled to the generator. This power trailer includes the inlet plenum, exhaust collector and diffuser, and the engine and generator lube oil system. Figure 1 is a 3D model of the structure and assembly use for design and structural analysis.

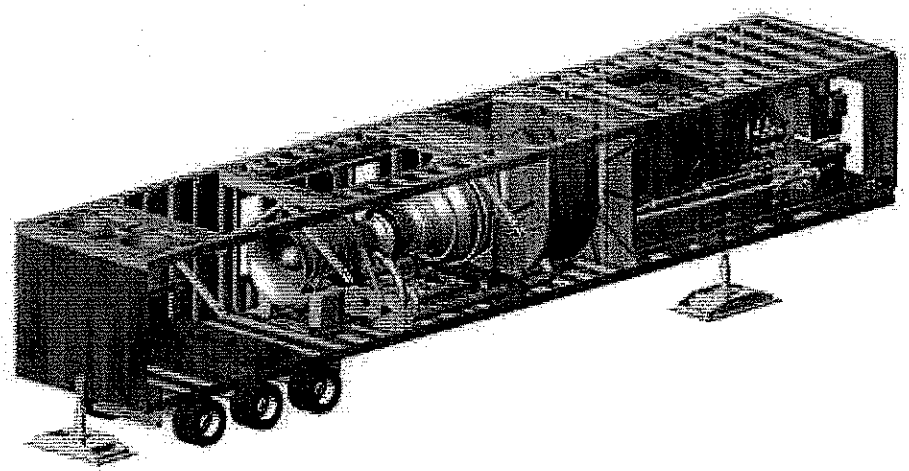


Figure 1: 3D Model of the MOBILEPAC

PWPS engineers designed a riveted aluminum monocoque structure for this power trailer. The structure is similar in construction to an aircraft hull in which the aluminum skin, riveted to stringers forms a strong yet lightweight container which reacts much like a reinforced cylinder to resist torsional, buckling and deflection loads. Basically, the skin of the trailer supports all of the static and dynamic loading of the gas turbine generator installation as opposed to reinforcing a conventional trailer with heavy channel and beam structures for strength. A 3-point support commonly used for installing gas turbine generator packages on offshore platforms and aboard ships is used. There is one outboard jacking and leveling plate located towards the rear of the trailer and two centered up front under the generator. Each of the three leveling plates sits on engineered fill compacted to 4000 lbs per square foot (or concrete pads at the option of the owner-operator) to support the trailer. The monocoque structure of the trailer acts as a solid plane to transfer its weight to the plates. Even if one leveling plate should sink, everything remains in plane so that the generator and turbine coupling alignment is not affected. The trailer is acoustically insulated to attenuate noise from the engine and generator. Figure 2 is a view of the power trailer under construction. Note the acoustical insulation. All electrical cables are brought to quick disconnect connectors on the enclosure wall. The picture is taken through the inlet as the plenum is not installed. The holes in the roof are for engine removal, exhaust and generator exhaust. The piping in the foreground is for engine lubrication oil.

The control trailer is built on a custom fabricated trailer. The control trailer includes a 15-kV circuit breaker, engine and station control system with monitor, protective relays and synch panel, batteries and charger, motor control center, PT auxiliary transformer and hydraulic start package and CO2 fire suppression. The control enclosure is heated and air conditioned to maintain a benign environment for the electronics.

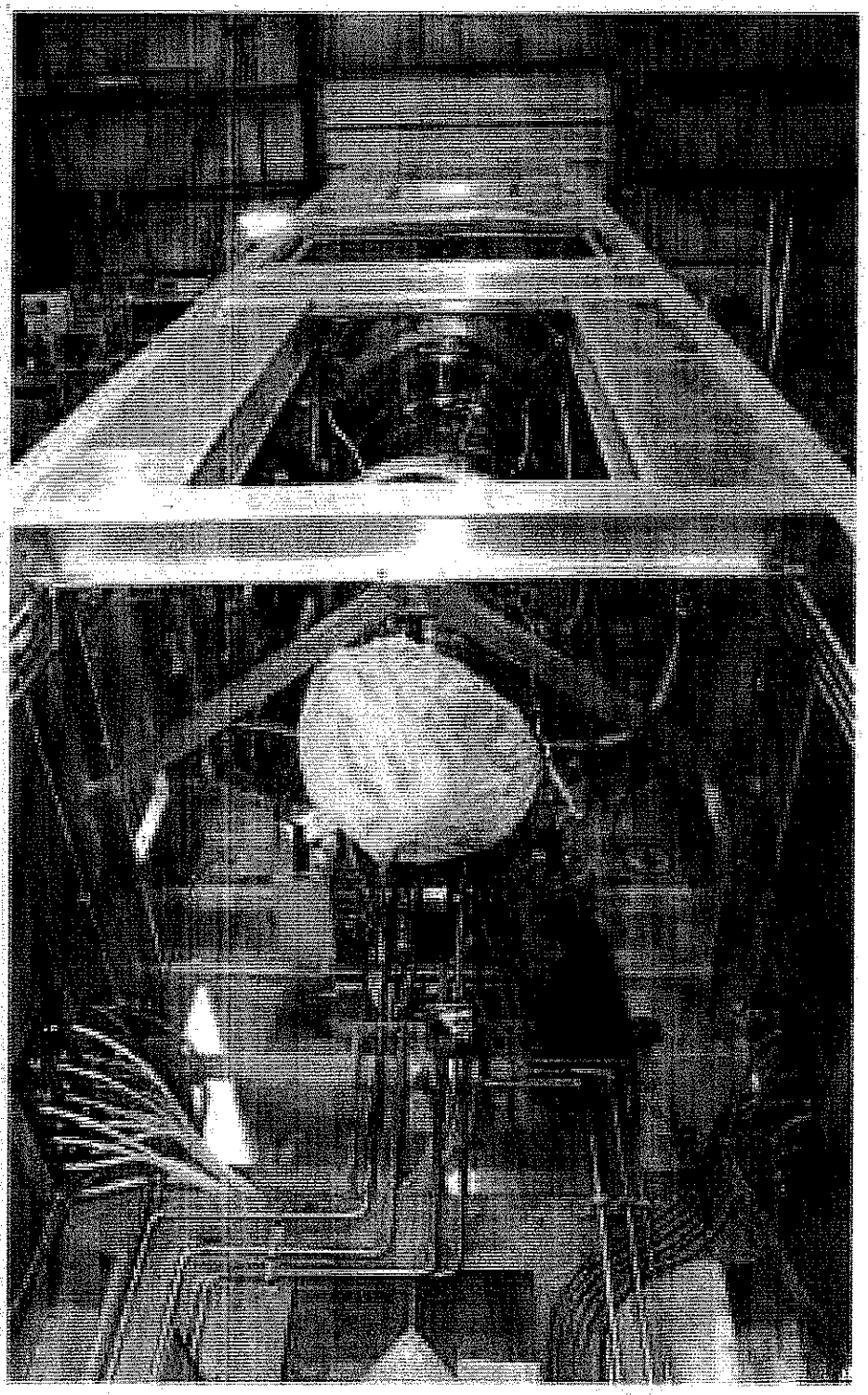


Figure 2: MOBILEPAC Power Trailer under construction

## Transportation

The power trailer is transported to its site by a jeep and wheeled tractor that fits to a pivot pin under the front of the trailer. A hydraulically steered 3-axle bogey located towards the aft end of the power trailer facilitates negotiating difficult roads and to position the trailer on arrival at the site. The power trailer suspension is equipped with an air ride system to absorb road shock. The suspension has pneumatic jacking to adjust for road clearance. This trailer is approximately 65 ft long by 12 ft wide and 13.5 ft high. Adequate clearance was designed on the underside of the trailer for highly crowned or undulating roads.

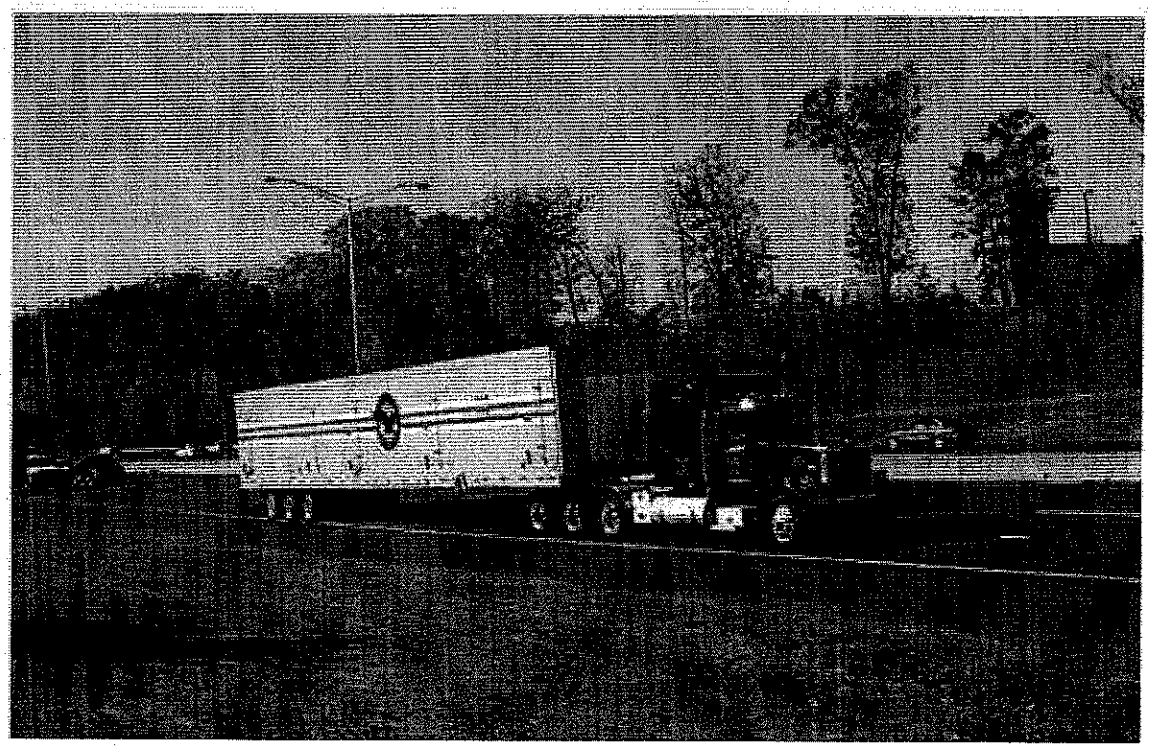


Figure 3: MOBILEPAC Power Trailer in transit on the Interstate.

The control trailer is about 50 feet long by 11.5 feet wide by 13.5 feet high. The control trailer suspension is also equipped with an air ride system to absorb road shock.

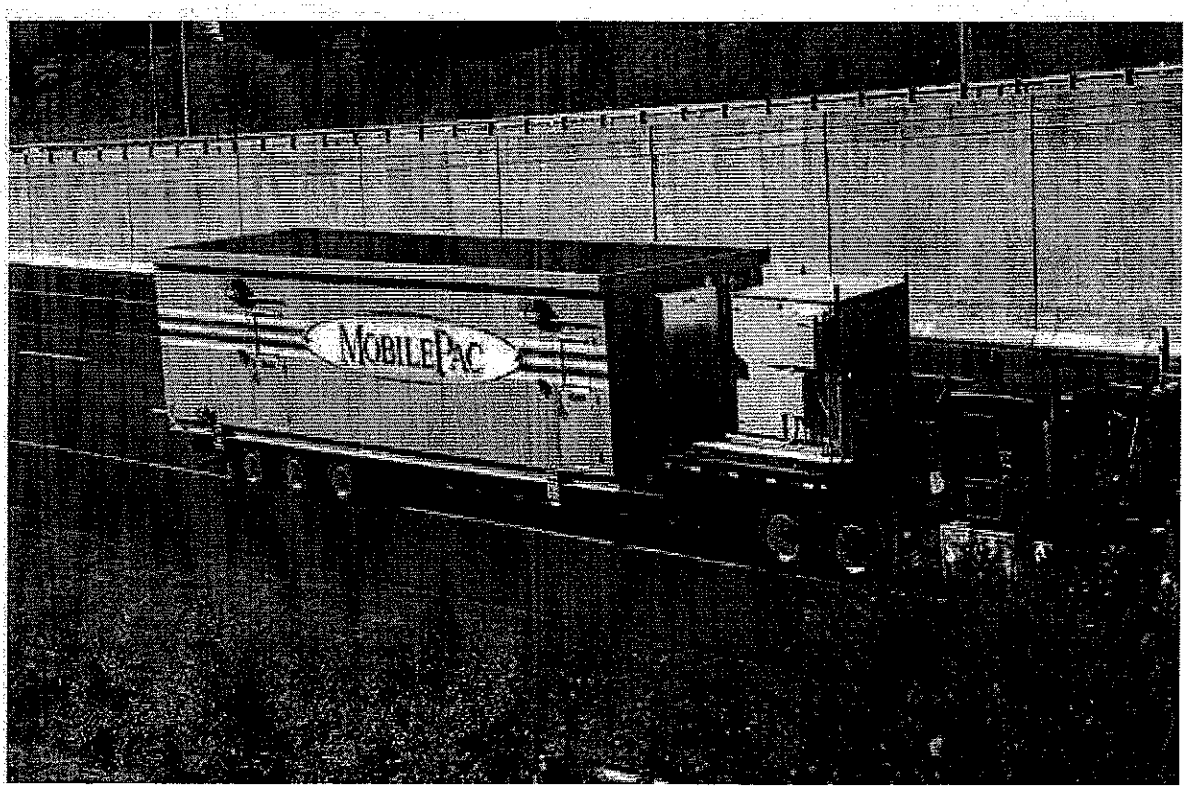



Figure 4: MOBILEPAC Control Trailer on the Interstate

Two standard trailers are used to deliver accessory equipment. One trailer carries three gas turbine exhaust stack sections, inlet air filter, and inlet silencer. The second one carries two exhaust silencers and, if specified as an option, water injection skid for NOx control. Each trailer is about 48 ft long by 11.8 ft wide by 13.5 ft high.

**MOBILEPAC Installation**

Depending upon site preference, the controls trailer can be set on the ground in line with the power trailer or parallel to it. In either case, the switchgear is positioned close to the generator. Little is required in the way of advanced site preparation to support the power and control trailers. There are no pilings or concrete pads required. The basics required are a mobile crane, site electrical power, a relatively flat surface and, for the power trailer, compacted soil areas for supports.

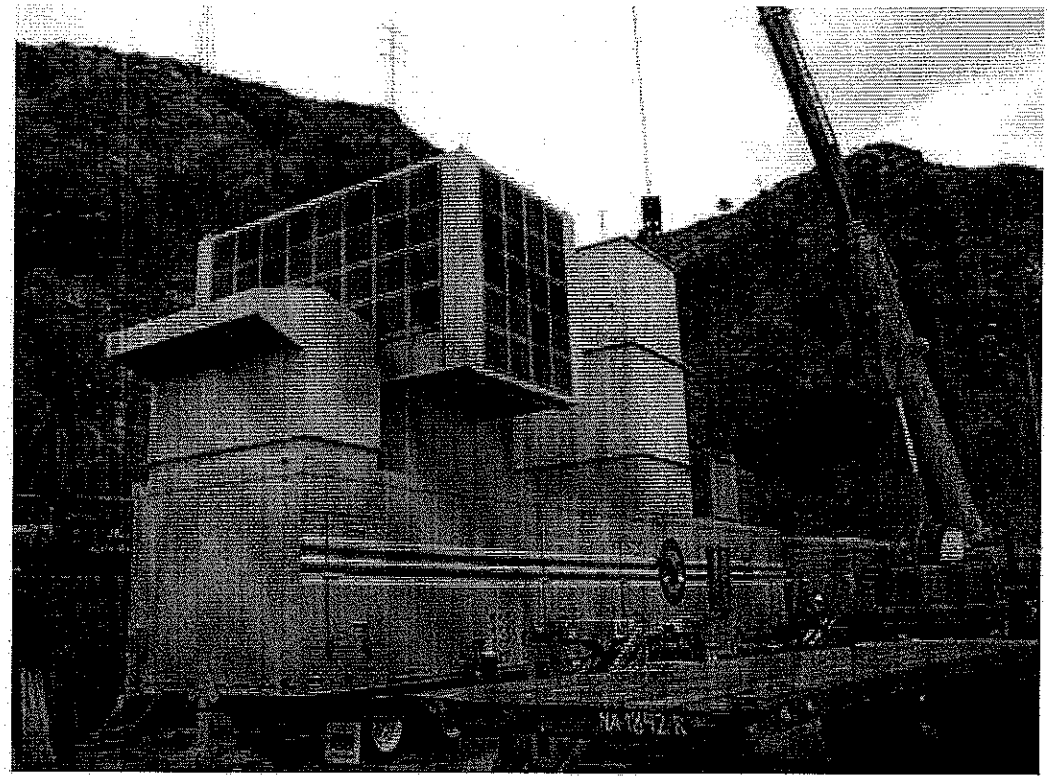


Figure 5: Assembly of Power Trailer, Control Trailer in the backround.

Upon arrival, air bags at the front and rear undersides of the power trailer are inflated to lift the trailer and take up the load, the jeep is unhitched and removed, and the trailer leveled using the jack plates. After the jacks are set and locked, the air bags are deflated. Electrical preparations include plugging in quick disconnect cables to mate with the already checked out turbine and plant control electrical signal systems. Mechanical preparation includes removing the shipping closures, connecting the cold air buffer, fuel and hydraulic start piping and hoses. Given a true emergency, the MOBILEPAC is ready to run without adding filtration or silencing. Therefore full power output could be supplied to the grid in 8 hours. A normal timetable includes installing exhaust stack sections (using crane supplied by operator-owner), exhaust silencers, and gas turbine inlet air filter and silencer – all of which go on top of the power trailer. Both accessory trailers remains on site just long enough to deliver (or pick up) the accessory equipment. This installation requires another 12 hours for mechanical and electrical preparations plus pre-operational system checkout by a 4-man crew working two 8-hr shifts.

All the plant requires to become operational is a fuel supply and a power connection to the grid.

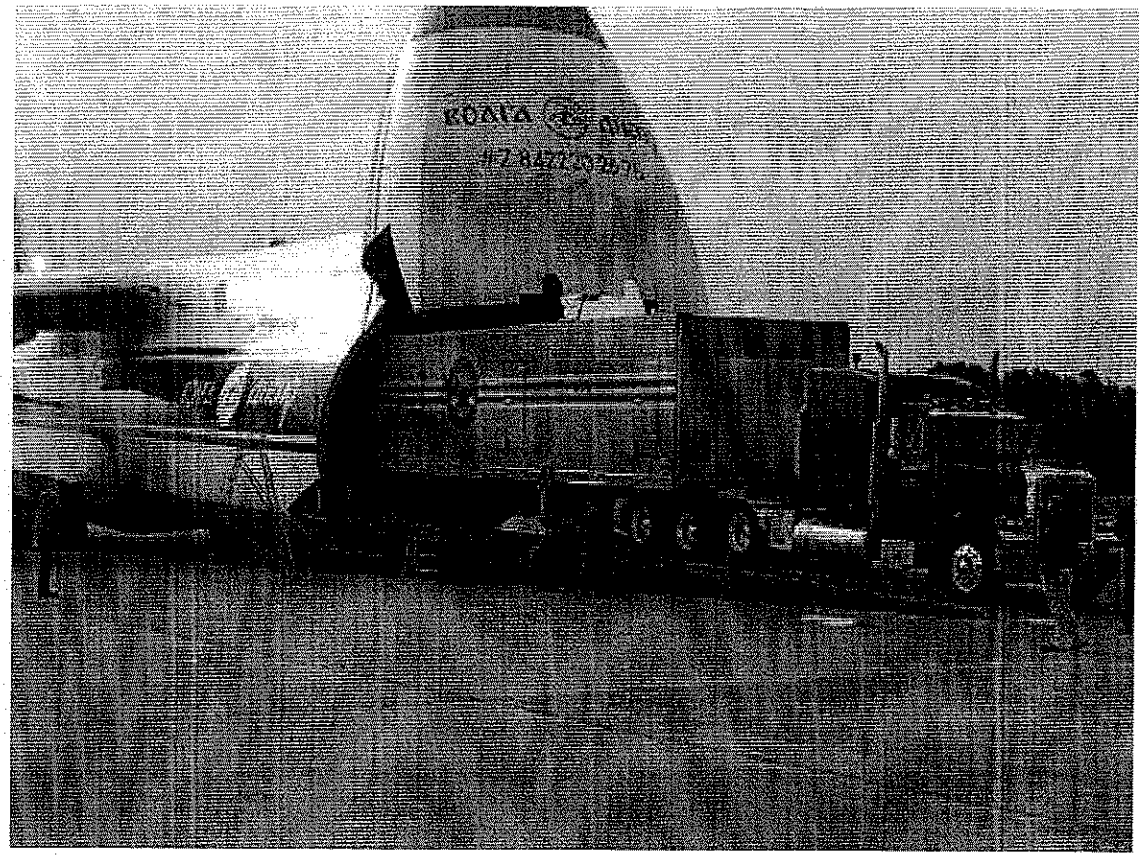


Figure 6: Trailers are designed for Air Shipment

**First Site**

The first installation of an FT8 MOBILEPAC was on La Palma in the Canary Islands. Since there was a need for power in the area and the island is somewhat remote, a MOBILEPAC was flown on a single plane, to an adjacent island and ferried to its final destination. Therefore transportation to this site verified that the MOBILEPAC is readily transportable by land, sea and air. The customer supplied truck mounted high side transformer and switchgear. Thus, a complete 25MW power plant is readily transportable. The only available site was on the side of a hill, on a terraced area, against a stone wall. The flexibility and relatively small size of the MOBILEPAC made this site a true success.

**Maintenance**

There is plenty of room around the gas turbine engine to carry out routine inspection and maintenance procedures. Access and working room inside the power trailer is the same as inside a stationary FT8 enclosure. For instance, there is full access around the combustors to inspect and replace fuel nozzles, cans and transition pieces (as required) without first having to remove other hardware that might be in the way. For removal or installation, it is necessary to

disconnect and move the gas generator away from the power turbine so that it can be hoisted out the removable roof of the trailer. If it is ever required to remove the generator, the end wall of the trailer is removable.

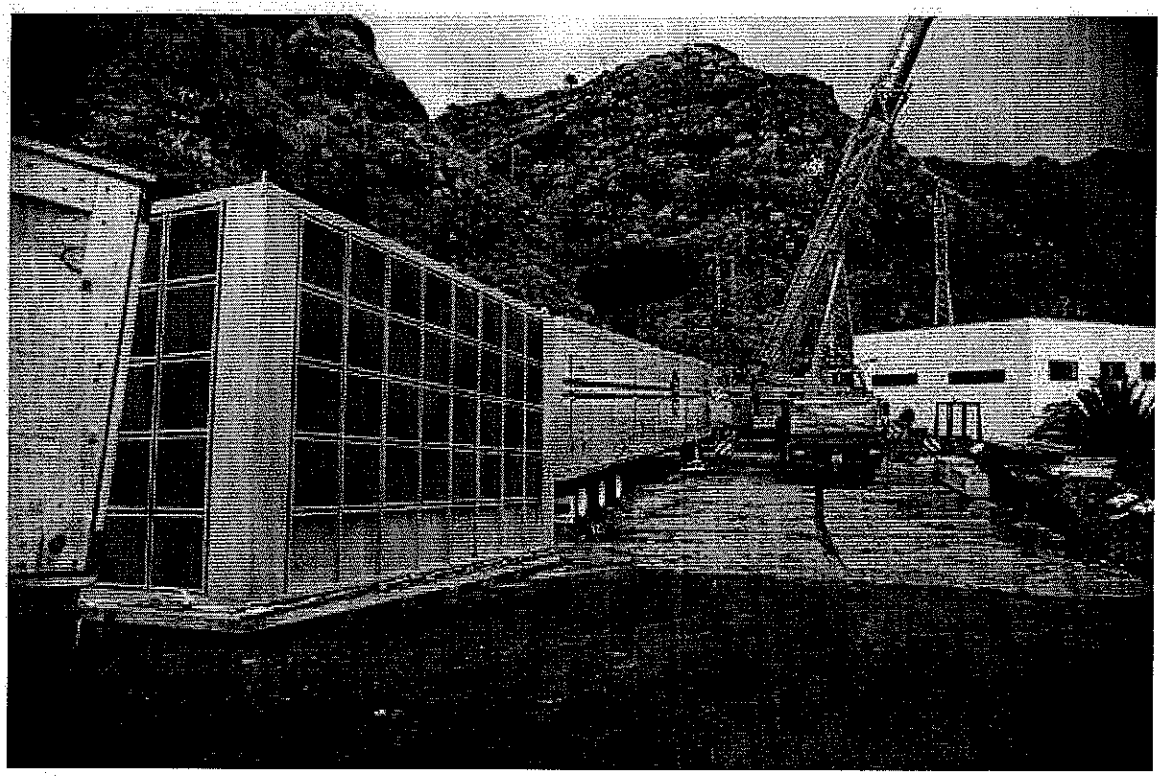


Figure 7: Mobile Site in the Canary Islands

**Other Features**

A MOBILEPAC can generate passive revenue by qualifying as "spinning reserve" or operate as a synchronous condenser when not needed for emergency back-up or peaking. It does not require a clutch to operate as a synchronous condenser due to its free power turbine. In the synchronous condenser mode of operation the plant can switch over to generate full 25 MW power output within 1 minute.

Should an emergency occur, a MOBILEPAC can be operated without filters and silencers. When time permits these components can be added later. Another potential advantage is the MOBILEPAC is not taxed as a permanent structure.

**Summary**

The new Pratt & Whitney MOBILEPAC incorporates several new design concepts resulting in the most flexible and highest performing mobile power plant on the market. Improved design concepts for trailer design, equipment alignment, and leveling technology, create a package that

lowers costs to the customer and allows emergency installation in as few as 8 hours at a wide range of sites.

# GAS TURBINE ON WHEELS

## Caterpillar helps ensure stable energy supply during Western U.S. power crisis with new XQ5200 mobile turbine rental units powered by Solar Taurus™ 60 gas turbines.

The recent power crisis in the Northwest region of the United States still has everyone, especially power producers, thinking about ways to reduce the demand on the electricity grid while continuing to provide adequate, quality power to consumers. Customers are responding by looking for alternatives to utility power from the grid due to concerns over power reliability and price volatility.

Caterpillar has taken a lead role during this power crunch by providing quality temporary power to customers in all areas of the U.S. Recently, the Caterpillar network expanded its temporary power alternatives by adding Taurus™ 60 Mobile Turbine Power Units. The units are manufactured by Solar Turbines Inc. (a Caterpillar company) and are being debuted in the Cat Rental Power fleet.

Designated the XQ5200 based on its ISO rating of 5,200 kW, these new industrial gas turbine power modules are portable, low-cost power alternatives incorporating Solar Taurus 60 gas turbine generator set packages and prefabricated power control room modules.

The increased electrical power prices in the Northwest, as well as the challenges associated with bringing a complete power plant online quickly, are two important reasons the XQ5200 is playing an important role in meeting peak seasonal and emergency power demands, according to Steve Garceau, Caterpillar rental power manager.

"Plans to build additional U.S. power stations are in the works," he notes, "but Northwest customers need power now." The XQ5200 provides that necessary power, quickly and cleanly.




### MOBILE POWER PLANTS

The new gas turbine power module is similar to traditional Caterpillar diesel power modules in its mobility. The trailer-mounted system is highway transportable and requires no concrete foundation, allowing it to be easily redeployed to other sites as needed.



*This Cat XQ5200 Mobile Power Unit incorporates gas turbine technology to provide an environmentally friendly power source that can be easily deployed and permitted.*

Quick setup is accomplished with a modular design including plug-in connections. The XQ5200 is dispatchable to be online in six minutes from cold start, which makes it ideal for utility rental applications.

The compact footprint of this turbine power module is a perfect fit for minimum space requirements common at substations and industrial customer sites. "Each XQ5200 is designed for less than 350 square feet per MW," confirms Dave Dunlevy, power generation manager for Solar Turbines.

At the core of the unit is the proven 5.2 MW Taurus 60 industrial gas turbine. The turbine is rated at 5,200 kW with a heat rate of 11,263 Btu/kW per hour. It has a proven history all over the world in more than 900 applications, from cogeneration and base load to distributed generation and standby.

Utility-grade switchgear and a programmable protective relay module are standard. A range of control system options for remote operation and Supervisory Control and Data Acquisition System (SCADA) compatibility are also available.

### POLLUTION PREVENTION

Meeting peak seasonal or emergency power demands with an XQ5200 is also an environmentally friendly alternative. Each gas turbine power module can be configured for natural gas, diesel fuel or dual fuel operation. (Dunlevy notes that the turbines are typically most economical when natural gas is the primary fuel.)

The system also utilizes a dry low emissions combustion system (SoLoNO$_x$™) for low emission levels. This type of system uses a lean premix combustion system, as opposed to water injection, to control emissions. Water injection, notes Dunlevy, can be costly for the operator as well as a logistical burden for the site.

Further environmental features include a low-profile design that minimizes installed height and meets most permitting requirements, and a sound-attenuated enclosure for quiet operation.

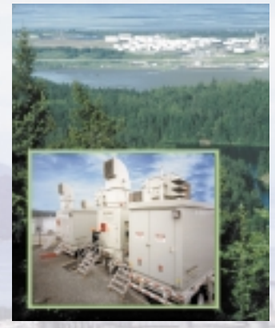
### DEALER NETWORK SUPPORT

Each XQ5200 is fully supported by the worldwide network of Cat Rental Power dealers. The network maintains the largest, most comprehensive rental fleet in the industry with more than 6,000 MW of power generation capacity, 50,000 tons of temperature control capacity, and a complete line of oil-free and oil-flooded air compressors and ancillary equipment.

For information on the XQ5200, contact Cat Rental Power at 800-RENT-CAT or visit www.CAT-rental.com. ■

## Washington refinery relies on Caterpillar XQ5200 rental units

The first customer to take advantage of the Cat XQ5200 Mobile Power Units is Equilon Enterprises LLC. The company is one of the Top 10 largest oil refineries in the United States. It is a joint venture between Shell Oil Company and Texaco Inc. and consists of four refineries that produce a combined capacity of 480,000 barrels of oil a day.



Equilon engineer Bill Tezak recently called on Cat rental dealers N C Power Systems (Tukwila, Wash.) and Peterson Power Systems (San Leandro, Calif.) for a short-term source of on-site power generation at the company's Puget Sound Refining Company (PSRC) in Anacortes, Wash.

"Peak wholesale power prices in Washington state spurred Equilon to look to other power alternatives," explains Gene Hamilton, sales engineer with Peterson Power.

"As an oil refinery, we need consistent power all the time," notes Tezak. "It became cost prohibitive for us to purchase all our power from the grid."

Working in conjunction with N C Power, Peterson Power responded to Equilon's temporary power needs with four Cat XQ5200 Mobile Power Units. The units provide 21 MW of electrical power for the refinery – approximately 60 percent of the refinery's total electrical load.

The four turbines are contracted for one year with an option to extend the rental. "These turbines are part of our solution for this year," says Tezak. "We don't know what's going to happen with the power market in the future and we want to be prepared."

Currently, the refinery is running the units continuously. Tezak plans to continue this operation schedule as long as it is economical.

### THE BENEFITS OF GAS

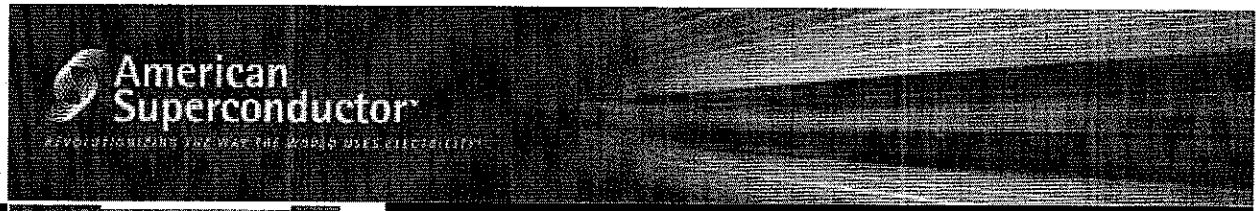
Gas turbines were a natural choice for the refinery, says Tezak, because of quick setup time and low emission levels. Fuel cost savings were also a key factor in the decision to use natural gas turbines.

"The modules have performed flawlessly," notes Hamilton, "with no unscheduled downtime during the first four months of operation." Scheduled maintenance is conducted every three months, and no full-time operator is needed to monitor the units due to the high reliability of the modules. Remote starting and monitoring functions are controlled inside the refinery.

Overall, Tezak is very happy with the XQ5200s as well as the Cat dealers who support them. "Peterson Power is an extremely helpful dealer," he reveals. "They've dealt with every problem and they've always gone beyond what they needed to do."

# APPENDIX 10
# DYNAMIC VAR COMPENSATION INFORMATION

# APPENDIX 10
# DYNAMIC VAR COMPENSATION INFORMATION






# Transmission Grid Solutions

## D-VAR® Solutions - Dynamic VAR Support for a More Reliable Grid

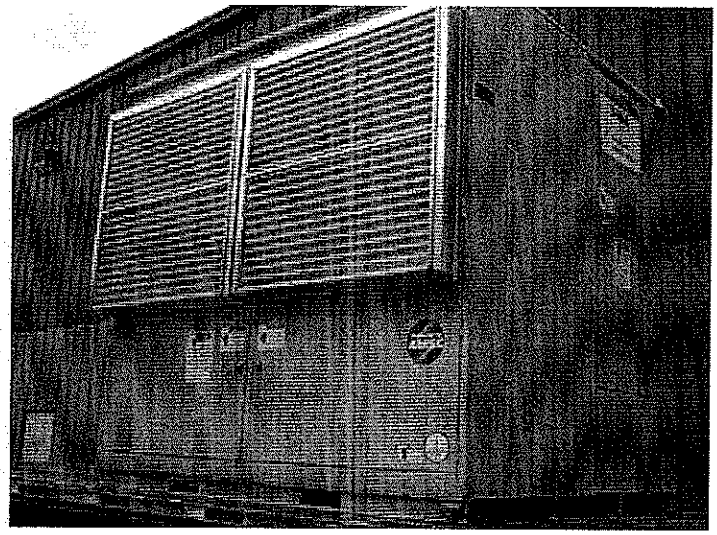
D-VAR® (Dynamic VAR) STATCOMS provide a powerful and cost-effective source of dynamic VARs for a wide range of operational needs. D-VAR systems utilize a proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power. At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. D-VAR STATCOMS can respond to voltage events that are both rapid and slow, providing the same level of security, reliability, and enhancement to the grid as an SVC. >>More information on AMSC D-VAR systems

AMSC D-VAR® (Dynamic VAR) reactive compensation systems provide a powerful and cost-effective source of dynamic VARs for a wide range of operational needs. They can correct voltage instability problems on transmission networks; provide dynamic steady-state voltage and power factor control and regulation on transmission and distribution networks; protect industrial facilities requiring premium power quality; and support a stable point of interconnection for distributed generation facilities and large-scale wind farms. Classified as Flexible AC Transmission System (FACTS) devices, D-VAR systems utilize an AMSC proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power, measured in VARs (volt amperes – reactive), precisely where it is needed on the grid. D-VAR systems are extremely flexible and scalable, ranging from 2 MVAR to hundreds of MVAR.

TRANSMISSIO
SOLUTION PR(
* D-VAR®
* SVC Static \
Compensatc
APPLICA
TRANSM
SOLUTIC
* Utilities
* Wind Energ
PRODUC
* Data Sheets
* Case Studie



CONTAC
For more infor
regarding our t
grid solutions,
contact us at:
pesinfo@amsu



**D-VAR systems are highly scalable and mobile solutions that allow utilities to install them in their power grid at locations that need the greatest amount of VAR support.**

At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. The D-VAR is composed of rack-able IGBT power module poles capable of producing capacitive and inductive VARs. It is an air cooled, current source system that, unlike capacitor-based systems, is not subject to the square of voltage de-rating factor at lower voltages. This advantage reduces the overall level of MVARs needed for some applications. The inverters also have a short term overload capability of 2.67-3.0x of the continuous rating for up to 2 seconds, providing extra capacity for post-fault voltage recovery.

**D-VAR Solutions Address Many Needs**

AMSC's D-VAR system was designed with flexibility in mind to address the many voltage and VAR related problems seen on the transmission grid. More AMSC D-VAR systems have been installed throughout the world than any other inverter-based (STATCOM) reactive compensation device. Applications to date include:

- Localized Voltage Collapse Problems
- Single Point, Large Block, Transmission Connected Solutions
- Increasing Power Transfer Through Stability Limited Systems
- Reducing and Retiring RMR Generation for Voltage Support
- Wind Farm Voltage Regulation/ Low Voltage Ride Through
- Voltage Regulation on Radial Lines, and in Weak Grids
- Mitigating Industrial Voltage Transients

**Benefits and Advantages of D-VAR Systems**

AMSC's D-VAR systems enjoy unparalleled success in the field for many reasons. Strong and continuing customer relationships, along with proven, reliable technology, have made AMSC an industry leader, providing cost effective solutions that will work when it counts the most. When deciding on what solutions are appropriate, consider some of the benefits and advantages of D-VAR reactive compensation systems:

- High density, advanced power converters
- Low cost, easily permitted solution
- Can be deployed as a single, large block solution or distributed around an area
- World leader in Statcom installations and experience
- Minimal footprint and easy to install, leading to lower turn-key costs
- Overload capability helps maximize performance
- Minimal preventative maintenance required
- Completely air-cooled
- Fault tolerant and robust design
- Modular, relocatable and easily expandable to meet future requirements
- High field availability

**Let our System Planning Engineers Help You**

AMSC's transmission planning team is highly experienced, and works closely with customers to develop optimized, cost effective solutions to improve their system reliability. Former utility network planners themselves, they understand your specific needs and your network's operating behavior. They model its characteristics in accurate detail to determine the system response and offer customized solutions to meet your particular requirements. Some of the services provided include:

- Load flow studies
- Dynamic stability analysis
- Transfer capability studies
- Power quality and reliability studies
- Harmonic analysis
- System impact studies

AMSC's team of network planners uses industry standard software. They will work with you to find a solution in any modeling software that you may use. Some of the software utilized by our team includes:

- PSS/E
- PSLF
- PSCAD
- PowerWorld

At AMSC we won't just sell you a product, but rather a complete and integrated solution. All of our systems include detailed application engineering analysis and associated simulations validating the performance of our equipment on your grid. This enables us to insure our recommended solution is accurate and efficient and catered specifically to

your needs.

Click here for more information on D-VAR reactive compensation systems, or to request a transmission planning study.

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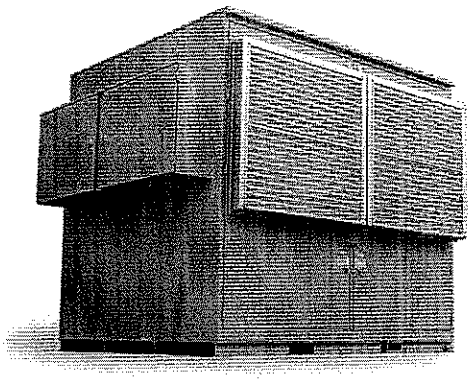
# Dynamic Reactive Power Compensation

## Utilizing State of the Art Power Electronics Technology

### Benefits

- Provides steady state voltage regulation
- Delivers superior transient response
- Improves grid reliability by stabilizing voltage
- Generates/absorbs VARs dynamically
- Modular construction enables quick deployment and future flexibility
- More compact and less costly to install than competing devices
- Highly efficient resulting in lower operating costs than other devices

The American Superconductor (AMSC) dynamic VAR (Volt Ampere Reactive) system is a powerful, cost-effective solution that dynamically stabilizes and regulates voltage on power transmission grids and industrial operations. Utilizing AMSC's proprietary PowerModule™ power electronic converters, D-VAR® systems detect and instantaneously compensate for voltage disturbances by injecting leading or lagging reactive power at key points on transmission and distribution grids. Each D-VAR solution is customized to meet specific customer needs and includes inherent flexibility to accommodate changing grid conditions.

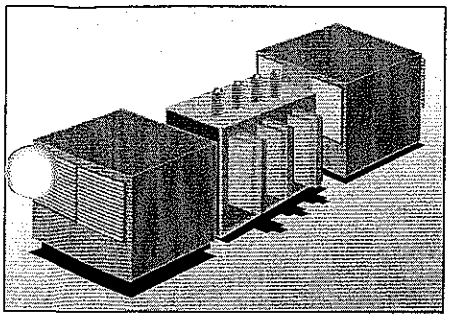


D-VAR systems are highly scalable and mobile solutions that allow utilities to install them in their power grid at locations that need the greatest amount of VAR support.

Transfer capacity of a power grid is often limited due to voltage instability. D-VAR systems provide a proven solution to address voltage stability issues and relieve associated constraints. D-VAR systems can be a valuable tool in increasing the power transfer capacity of the grid.

D-VAR systems allow wind farms to meet utility interconnection requirements including low voltage ride through (LVRT), voltage regulation and power factor correction. D-VAR systems can also mitigate transient voltage events and "soft switch" capacitors which extends the life of wind turbine gearboxes, switches and other components.

AMSC's transmission planning team has over 75 years of experience in transmission and distribution planning. This team will help you analyze your system by performing studies for low voltage, voltage stability, transfer capability and power quality problems. They will help you develop the least costly, most effective solution to alleviate your short and long term problems.



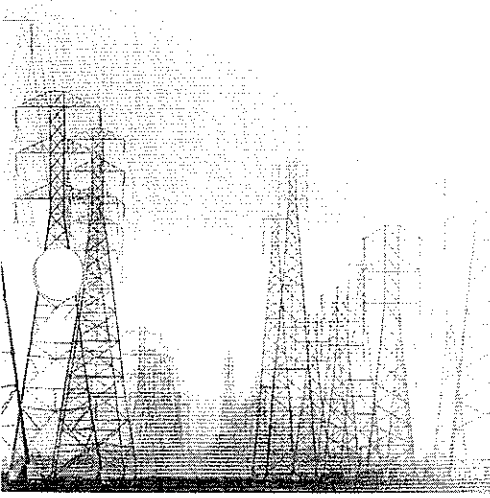
Example of an 8 MVAR D-VAR system which is 30 feet long by 11 feet wide. D-VAR systems are modular and compact and accommodate areas with restricted space availability.

## Specifications

| | |
|---|---|
| Connection: | Medium Voltage (up to 46 kV) |
| Frequency: | 50 or 60 Hz |
| Continuous Rating: | ±2.0 to 100s of MVARs |
| Transient Overload Rating: | 2.67 time continuous for up to 2 seconds (application-specific) |
| Response Time: | Sub-cycle |
| Inverter: | IGBT, 4 quadrant, stacked units, 4 kHz switching frequency, rated at 1 MVAR, continuous duty |
| Output: | Independent phase control |
| Harmonics: | Per IEEE 519 |
| System Monitoring: | Digital recording of system action, multiple inputs, alarms and warning signals |
| Ambient Temperature: | -50°C to +50°C |
| Other: | Mobile configuration for quick deployment<br>Minimal on-site installation<br>Compact installation for minimal footprint<br>Remote monitoring<br>Environmentally benign<br>Ambient air cooling<br>Current source not subject to square of voltage de-rating factor at lower voltages as in other systems based solely on capacitors |

## Product Applications

| | |
|---|---|
| Reactive Compensation | Transmission and Distribution Systems |
| Steady State Voltage Regulation | Long Radial Delivery Systems, Wind Farms |
| Increasing Grid Capacity | Transmission Systems |
| Reduce Reliability Must Run Generation | Transmission and Distribution Systems |
| Voltage Sag Mitigation | Large Industrial Facilities, Wind Farms |



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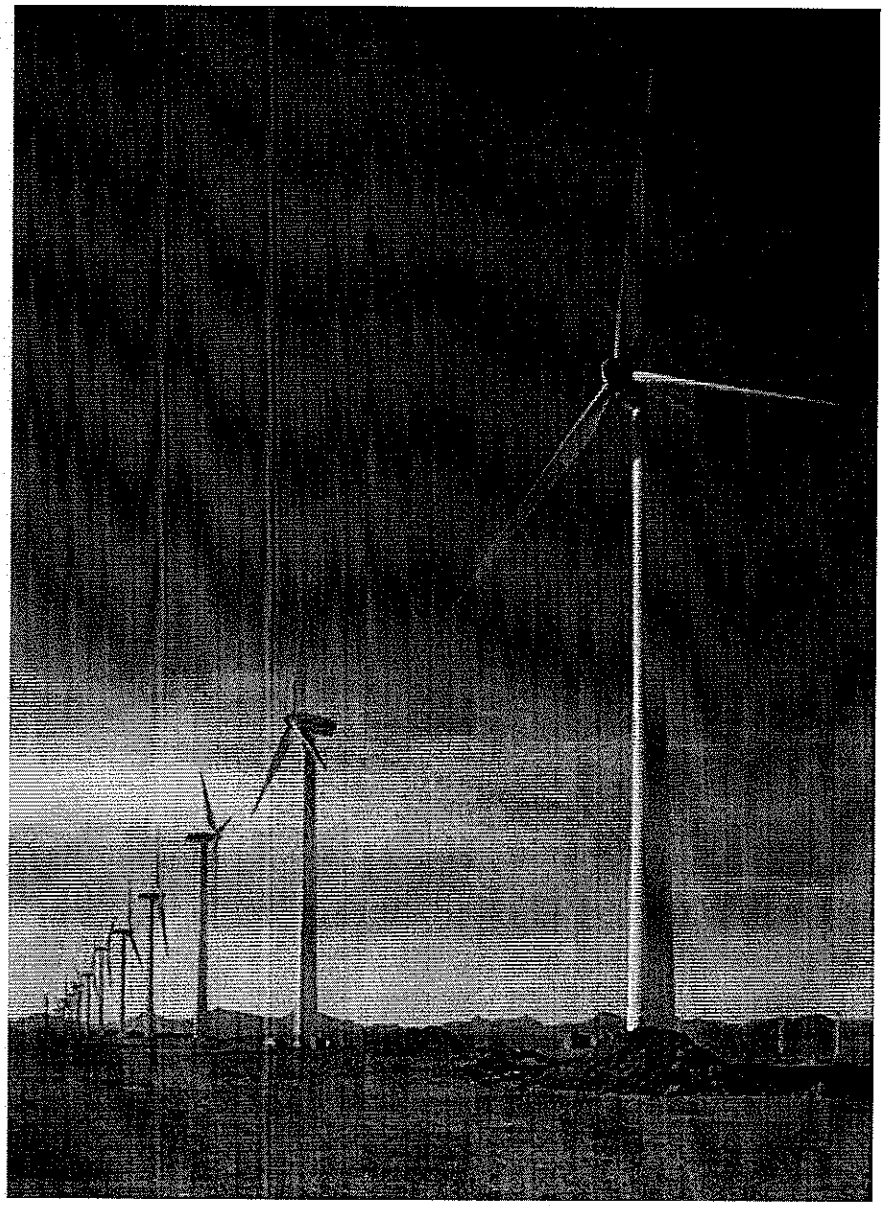
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REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

# Optimizing Reactive Compensation for Wind Farms: Meeting Today's Utility and Regulatory Requirements

***A White Paper by American Superconductor Corporation***



# How Dynamic VAR Technology Enables Wind Farms to Meet Grid Interconnection Requirements

## Executive Summary

Wind energy is one of the fastest-growing sources of electricity in the United States and around the world. The growing importance of wind power has subjected it to greater scrutiny and more rigorous operational standards than ever before. As wind-generated power transitions from boutique status to a full-fledged power source, it has become apparent that the industry needs smarter and more appropriate solutions to address common voltage regulation and dynamic voltage stability-related interconnection requirements.



Wind farm generation costs have fallen by 50 percent over the last 15 years, moving closer to the cost of conventional energy sources, according to the Global Wind Energy Council.

Advances in dynamic volt ampere reactive (VAR) technology, coupled with innovative applications and services, eliminate the drawbacks of traditional voltage and power factor control methods and enable wind developers to meet today's more stringent and specific interconnection requirements. This white paper explores the background issues, available solution alternatives, including the installation of a dynamic reactive compensation system manufactured by American Superconductor (AMSC) and operational considerations for addressing voltage and power factor control in the context of a wind farm and its interconnection to the grid.

Historically, wind farm operators have employed mechanically-switched capacitor banks to regulate voltage at the point of utility interconnection. However, due to its highly and continuously variable nature, wind-dependent technology is poorly served by this traditional approach. There are two reasons for this. First, wind turbines, especially many of the induction type, can draw large amounts of reactive power (VARs) from the grid. This dependency triggers frequent remedial action to maintain voltage levels within the tolerances established by regulatory requirements. Although wind energy is variable, capacitors are able to switch only fixed amounts of VARs, and furthermore once they have been switched off they must wait five minutes until they can be re-energized in order to allow their trapped charge to dissipate. Accordingly, it is often difficult to maintain optimum amounts of reactive compensation for any length of time using switched capacitor banks alone. Second, in some instances, switching banks of capacitors to regulate voltage levels has been reported to cause excess stress on the wind turbine gearboxes.

Capacitor banks typically offer the lowest first-cost option for the control of voltage on a scheduled basis, and will undoubtedly remain a central element of almost every wind farm reactive compensation system. However, wind farm interconnection requirements often can not be satisfied with capacitor banks alone. Optimizing reactive compensation for wind farms merits a wider perspective that addresses the physical interconnection with utility grids, specific interconnection regulatory requirements, the business relationship with the utility itself, and the cost of operation and ownership of wind farm equipment. In extreme cases, especially in weaker areas of the grid, deficient interconnection schemes can even affect a wind farm's megawatt output and jeopardize revenues by forcing wind farms off-line. In this broader context, it is very important to design the reactive compensation system after careful analysis of the grid dynamics at the point of interconnection.

## Executive Overview of Voltage and Power Factor Control

This overview section discusses basic background information and issues, and is intended to provide the framework for understanding the problems that Dynamic VAR technology can resolve and the extended benefits that it provides.

## What Are VARs?

Power consists of two components: real power and reactive power. Real power, which is the functional element that can do work (driving machines, lighting lights, etc.) exists when the voltage and the current are in phase with each other. Reactive power, on the other hand, exists when the voltage and the current are out of phase by 90 degrees. Although reactive power is unable to provide actual working benefit, it is often used to adjust voltage; so it's a useful tool for maintaining desired voltage levels. Every AC transmission system always has a reactive component, which can be expressed as "power factor." If the power factor is low and inductive (due to the wind turbine or other electrical equipment), then VARs are being drawn off of the grid, which reduces the system voltage. If the power factor is capacitive, then VARs are being added to the grid, which raises the system voltage. Some method is needed to manage power factor by injecting or absorbing VARs as necessary in order to maintain optimum voltage levels and optimize real power flow.

## How is Voltage Commonly Controlled?

Traditionally, the easiest and least-cost way to manage VARs is to install shunt capacitor or reactor banks on the transmission system. Calculations determine how many VARs are needed at any given point, and appropriately sized banks of capacitors are strategically placed (usually rated in MegaVARs; 5 MegaVARs or 10 MegaVARs, for example). As voltage levels fluctuate, capacitor banks are switched on or off to either inject more VARs into the system or remove them, as required. The effect is that the system voltage is maintained within tolerances established by the transmission owner as well as regulatory requirements.

*"Wind energy has now reached the milestone of 50GW of worldwide installed capacity and the industry is ready for a broader roll out. Wind energy has the maturity, clout and global muscle to deliver deep cuts in CO2, while providing a hedge against fluctuating fossil fuel prices and reducing energy import dependence."*

Arthouros Zervos
Chairman, Global Wind Energy Council
September 2005

## Capacitor Bank Switching Stresses Wind Farm Equipment

Although a cheap way of compensating for VAR losses, capacitor bank switching also results in an immediate, abrupt step-change in the voltage on the grid or the bus to which they are connected. The step-change instantaneously increases the torque, or twisting force, on a wind turbine gearbox. The variable nature of wind generation itself often triggers an extremely high number of the switching events that in some cases can begin to affect the reliability of the gearboxes. Like all induction motors, many induction-type wind turbines draw VARs off of the grid in amounts that fluctuate with changes in wind speed at the turbines. This, in turn, can cause an unacceptably large voltage drop at or near the wind farm interconnection point with the grid. So, given that these VARs need to be compensated in order to maintain voltage, it is not uncommon for a large site to experience fifty to a hundred switching events a day. In some cases the resulting gearbox stresses eventually take a toll, accelerating maintenance cycles of the gearbox.

## Remote Locations Complicate the Issue

The size of capacitor banks that can be used is governed by the strength of the grid or bus. Conventionally, the size of step-change in voltage from a switching event must be kept below a certain percentage of total voltage (typically two percent or below). A step change in voltage of any larger magnitude can potentially cause problems with other equipment in the substation at the wind farm. While first cost considerations may drive a preference for solutions employing fewer and larger capacitor banks, local conditions often require the use of a series of smaller banks relative to the strength of the grid at that location. Given that most wind farms are located in remote areas, the typical grid to which they connect is quite often relatively weak at that point because these grids are isolated from the generation sources.

## The Business Side of Voltage and Power Factor Control

The party responsible for regulating the voltage at the wind farm is typically the wind farm owner. With the increasing prevalence of wind generation in recent years, the issue of grid connection requirements for wind farms has come under heightened scrutiny by regulators as well as regional transmission organizations and reliability councils. As a result of new rules such as those issued by the Federal Energy Regulatory Commission, wind farm owners in the United States are responsible for complying with more stringent and specific requirements related to voltage control and high or low voltage ride-through (the ability of the wind turbines to stay

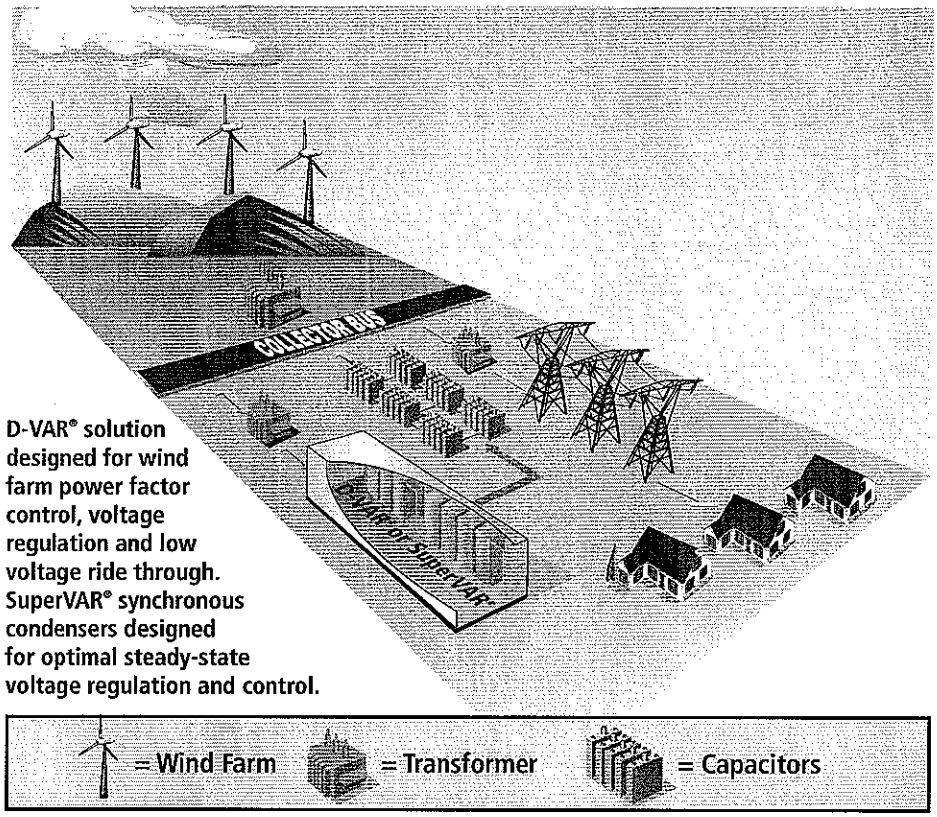
connected to the grid during voltage disturbances) for their wind farm than was the case in the early years of the emerging wind power industry. That responsibility is, in turn, driving wind farm owners and turbine manufacturers to incorporate dynamic VAR technology into their projects to enable compliance with these standards.

Regardless of who is responsible, all the parties have a vested interest in effectively and economically meeting the grid connection requirements. The ultimate objective, of course, is to ensure that wind farms provide a consistent, dependable source of real power generation while operating at peak efficiency and uptime with manageable cost of ownership. But also important to the utility is the power quality and reliability delivered to their other customers on the grid.

## D-VAR® Systems: An Ideal Strategy for Wind Farm Applications

In recent years, AMSC's D-VAR technology has become a preferred and innovative solution to address grid interconnection requirements associated with wind farms. In addition to addressing grid connection requirements, the D-VAR system provides additional operational benefits such as mitigating step-voltage changes. It does this by using advanced power electronics, often in combination with traditional capacitor banks, to dynamically inject or absorb precise amounts of VARs into the system. Where capacitor bank switching alone is a binary on-off action, dynamic voltage control is more akin to a radio volume control with fluid, continuously adjustable levels.

D-VAR technology offers an economic strategy for complying with interconnection requirements that also can act as a two-way shock absorber, not only resolving VAR demand and/or voltage control issues created by the wind farm, but also enhancing the ability of sensitive wind turbine generators to avoid tripping off-line due to common voltage disturbances that occur on the transmission grid. Keeping wind turbine generators on-line has proven to be, in some locations, a significant problem with today's wind farms, and dynamic VAR technology is often worth the investment for this reason alone.




**D-VAR® solution designed for wind farm power factor control, voltage regulation and low voltage ride through. SuperVAR® synchronous condensers designed for optimal steady-state voltage regulation and control.**

= Wind Farm = Transformer = Capacitors

For wind farm owners, the D-VAR solution delivers several significant side benefits beyond ensuring compliance with standards. The elimination of switching-related stress on the gearboxes in some cases reduces maintenance requirements and extends the life of the equipment. Furthermore, because sudden voltage disturbances on the collector bus are mitigated, by using this solution, the wind farm has enhanced ability to ride through transient high or low voltage conditions. This maximizes the megawatt output and increases revenues.

For utilities, the D-VAR system eliminates large VAR demands and the resulting voltage swings caused by uncompensated wind farm operation. With this system in place, the wind farm looks to the utility much more like a conventional synchronous generator, in terms of the ability to dynamically control voltage. This mitigates or eliminates the need to install capacitor banks on the transmission system to control voltage. In cases where capacitor banks are called for, solutions may involve a smaller number of units with larger ratings — leading to lower costs for the utility with the added ability of the D-VAR system to offset these larger step voltage changes and smoothly switch capacitor banks.

With its integral control system, the patented D-VAR system can be custom-fitted to specific wind farm facilities. For example, a small (8 MVA) D-VAR device can be combined with a number of low-cost, medium-voltage capacitor banks to create an integrated, effective voltage and power factor control system for a wind farm.

AMSC has also developed DVC™ (Dynamic VAR Compensator) solutions and SuperVAR® machines that can address similar issues as the D-VAR system. DVC systems have been developed to address the need for large-scale solutions requiring

hundreds of megaVARs (MVARs) of reactive compensation connected directly to the transmission grid. AMSC's DVC solutions are based on the widely successful D-VAR platform. They are a hybrid STATCOM/SVC solution that utilizes inverter-based FACTs (Flexible AC Transmission Systems) technology similar to D-VAR systems along with proprietary fast-switched capacitors and reactors.

SuperVAR machines use standard synchronous condenser frames and stator coils paired with advanced power-dense rotor coils made from AMSC's superconductor wire. The result is a synchronous condenser that is more efficient than conventional rotating machines — without the high rotor maintenance costs typical of older, conventional synchronous condensers.

SuperVAR machines are specifically designed for continuous, steady-state dynamic VAR support, with lower standby losses, higher output, and greater reliability than conventional synchronous condensers.

SuperVAR machines are cost-effective solutions that can provide tight voltage regulation and power factor correction to alleviate fluctuating voltage and VAR demands at wind farms.

## How D-VAR Systems Work

D-VAR systems are dynamic reactive power sources of the flexible AC transmission system (FACTS) classification. As depicted in Figure 1, D-VAR devices are installed on the wind farm collector bus, continuously monitor the voltage at the point of grid interconnection, and take precise, instantaneous action as necessary. The variable output of the D-VAR device is typically the first source used to regulate voltage. As additional compensation is required, the patented control system of the D-VAR system will switch a capacitor bank (or reactor) in or out. At the exact moment of switching, the DVAR device instantaneously injects (or absorbs) the same amount of VARs as the capacitor bank, thereby eliminating the step voltage change that would otherwise occur. The D-VAR system then resumes its normal voltage regulation mode, dynamically injecting or absorbing VARs as required. Notably, because of the capacitive and inductive capabilities of the D-VAR system it can handle a significant percentage of the events that would otherwise traditionally trigger a capacitor-bank switch; the annual number of capacitor switching events can be reduced. This results in less maintenance time and lower cost of ownership of the capacitor bank switches or breakers.

In addition to the operation inside the wind farm that Figure 2 shows, the D-VAR system can also help protect the wind farm from voltage disturbances that normally occur on the transmission grid (such as voltage sags or swells). The sensing and control scheme of the D-VAR system continuously monitors the voltage at the wind farm collector bus or point of connection to the transmission grid. When the voltage rises or

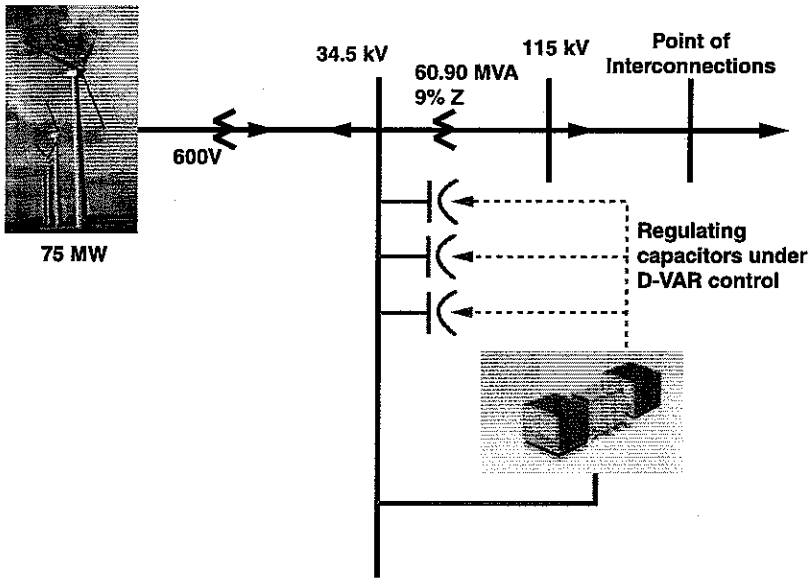



**Figure 1:** Typical Dynamic VAR System and Capacitors Connected to a Wind Farm. The dynamic VAR system shown in the figure continuously monitors the collector bus and/or transmission grid voltage of a typical wind farm to ensure that the voltage remains within the utility specified range. Continuous voltage regulation is accomplished by a combination of VAR injection or absorption from the dynamic VAR system, and by controlled, seamless switching of capacitor banks. In addition, the system mitigates voltage transients that typically originate on the transmission grid and can cause the wind turbine generators to trip off-line.

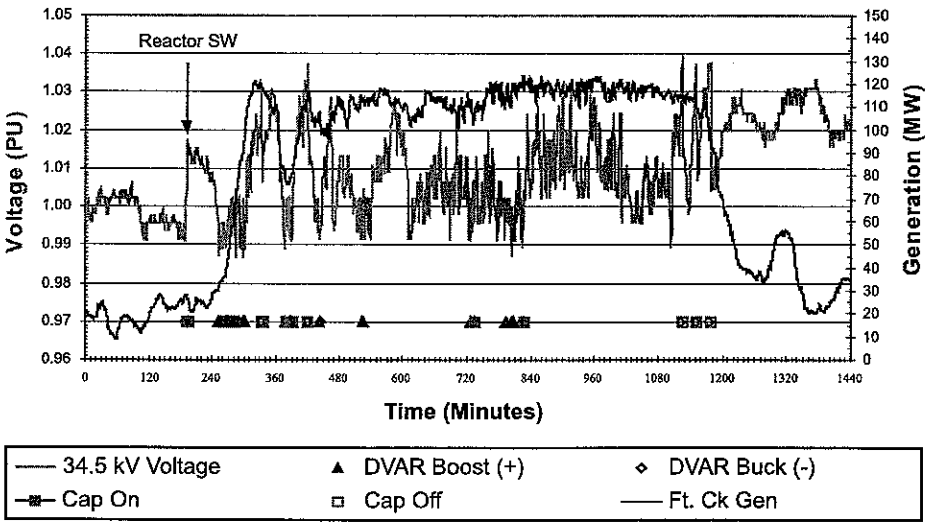



**Figure 2:** Example of a tight voltage profile maintained through varying wind conditions at an existing 130MW wind farm using a D-VAR system solution.

falls to a level outside a preset target or bandwidth, the D-VAR system responds instantaneously. It injects or absorbs sufficient reactive power to fully offset the event, maintaining the voltage inside the desired bandwidth levels.

## Considerations in Developing a Site-Specific D-VAR Solution

Although there are some factors that are common to all wind farm sites, each has unique aspects that must be considered when specifying the voltage and power factor control solution. Some wind farms will be fortunate enough to interconnect with a very strong grid that can tolerate the VAR demand of the wind farm without the assistance of anything more than simple capacitor banks. Other wind farms may be small enough that their operation does not negatively affect the transmission grid or they fall below the minimum MW size to which less stringent standards apply.

*"Wind power's rapid growth provides what is potentially the quickest and best supply-side option to ease the natural gas shortage."*

Arthouros Zervos
Chairman, Global Wind Energy Council
September 2005

These situations are somewhat unusual, however, due to two aspects of the basic economics of wind energy. First, scale economies are driving the construction of larger wind farms that have higher output relative to the local capacity of the grid. Second, wind farms by their nature tend to be located in remote areas where power delivery grids are not as strong. As a result of these factors, many wind farms require a voltage control strategy both to ensure compliance with regulatory interconnection standards as well as to ensure optimal operation. Factors to consider include the strength of the local grid connection, the size of the wind farm, the type of wind turbine generator and the interconnection specification of the grid owner. The best way to develop a strategy for voltage control is to do a site-specific analysis. This includes a detailed technical analysis of the grid strength and requirements, and results in an in-depth report with recommendations.

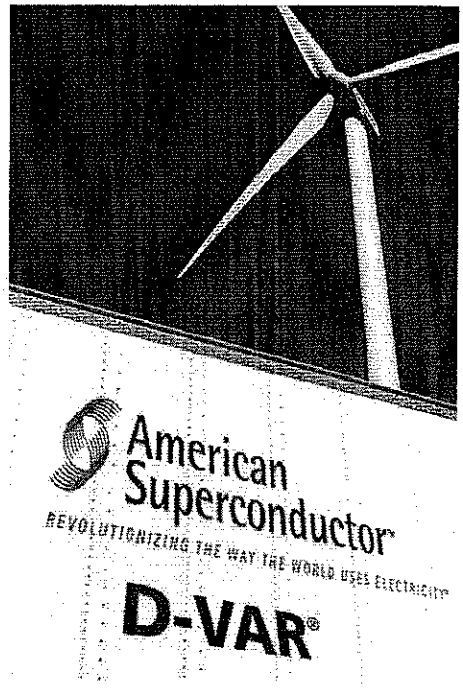
American Superconductor's staff of very experienced utility transmission planners will provide these studies free of charge or obligation. The company makes these services available to its customers because it believes it is the first step in understanding system requirements that will lead to recommendations for the best and most economic solution to meet these needs.

## Some Cost of Ownership Factors

Wind generation facilities are long-term investments, so in order to accurately evaluate the reactive compensation options, ongoing and cumulative cost of ownership must be factored in with the initial cost of infrastructure elements. Most often this includes a calculation of the cost of running a system over time, taking into account losses and efficiencies. These losses include the amount of power necessary to operate the balance of plant equipment, including reactive compensation solutions — power that must be paid for.

For example, as with almost all power equipment, cooling is a consideration. With power electronic devices, the two basic choices are liquid cooling and air cooling. Air cooling, of course, is much less complicated because it does not require plumbing, pumps, etc., and the ongoing operational and maintenance costs are also substantially lower because the more simple air-cooled system draws significantly less auxiliary power than a conventional liquid cooled system.

Another factor to consider is the flexibility of the control system. This is not only important in the initial phases




of the installation but also after the wind farm is up and running because it governs how closely the equipment can be further tuned to the specific wind farm conditions and requirements. One important item to consider in designing a wind farm is the willingness of the supplier to customize their product. Conditions are also likely to change over time, and the inherent capability of the control system to be adapted as the wind farm changes or expands is also critical. In addition, like all similar equipment, dynamic VAR devices have maintenance requirements. Is the manufacturer able to offer sufficient levels of support? For example, some systems such as the D-VAR system or DVC devices from AMSC can be monitored 24/7/365 by the manufacturer, either at very modest cost or as part of an annual maintenance package. This kind of service reassures wind farm owners that the devices are working properly and providing the protection and reliability they expect. Other services should include full hardware and software support specific to the installation. The maintenance factor is part of the ongoing and lifetime cost of ownership.

## Summary

It is very commonplace for today's generation of wind farms – larger-scale operations located in remote areas of the grid – to require more sophisticated voltage control strategies than their early predecessors. Wind farms also can have unique circumstances and operational considerations that warrant evaluation of the merits of traditional "voltage control by capacitor banks" approach. Employing dynamic VAR devices, sometimes in combination with control of capacitor banks, eliminates many of the negative consequences of traditional solutions. Both the wind farm developer/owner and ultimately the utility benefit from this approach.

## The D-VAR system advantages for the wind farm include:

- Grid interconnection standards are met.
- Voltage sags or swells originating from the transmission grid are mitigated. This enhances the ability of the wind farm to stay online and helps to prevent nuisance tripping of the wind turbine generators. This also helps maximize the power output of the wind farm which leads to increased revenues.
- Step-voltage changes due to local or remote capacitor-bank switching are mitigated, or eliminated, thus preventing excess gearbox stress or failure.
- Capacitor-bank switching events are minimized, which reduces switch maintenance costs.
- Overall grid interconnection costs are minimized.

## The D-VAR system advantages for the utility:

- Large VAR demands are eliminated, as are the resulting voltage swings caused by uncompensated wind farm operation. The wind farm maintains a consistent, smooth voltage profile.
- In some cases, the need to install additional capacitor banks on the transmission system is eliminated.
- If transmission capacitor banks are installed for any reason, their impact to the local wind farm is minimized.

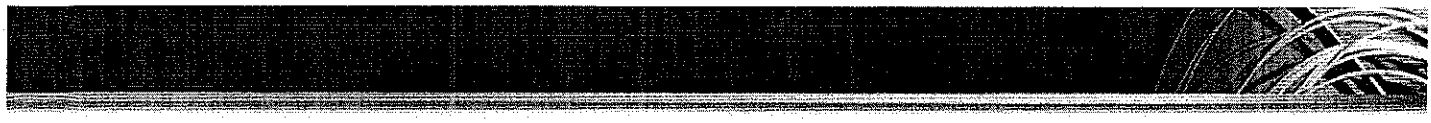
## About American Superconductor Corporation

American Superconductor (AMSC) is the manufacturer of the D-VAR and DVC dynamic reactive compensation systems which provide voltage support to utility transmission and distribution systems. In addition to wind farms, AMSC D-VAR systems are also being used worldwide to address a variety of grid-related problems such as voltage instability, power transfer constraints and steady-state voltage regulation.

AMSC is the world's principal vendor of high temperature superconductor (HTS) wire and large rotating superconductor machinery, and it is a world leading supplier of dynamic reactive power grid stabilization products. AMSC's HTS wire and power electronic converters are at the core of a broad range of new electricity transmission and distribution, transportation, medical and industrial processing applications, including dynamic reactive power grid stabilization solutions, large ship propulsion motors and generators, smart, controllable, superconductor power cables and advanced defense systems. The company's products are supported by hundreds of patents and licenses covering technologies fundamental to Revolutionizing the Way the World Uses Electricity™. More information is available at http://www.amsuper.com.

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# Transmission Grid Solutions

## DVC™ - Dynamic VAR Compensator Solutions

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The DVC systems are modular and scalable. They can be customized to meet any dynamic reactive compensation need and are built in sizes ranging up to several hundred MVAR connected to a single point on the transmission grid.

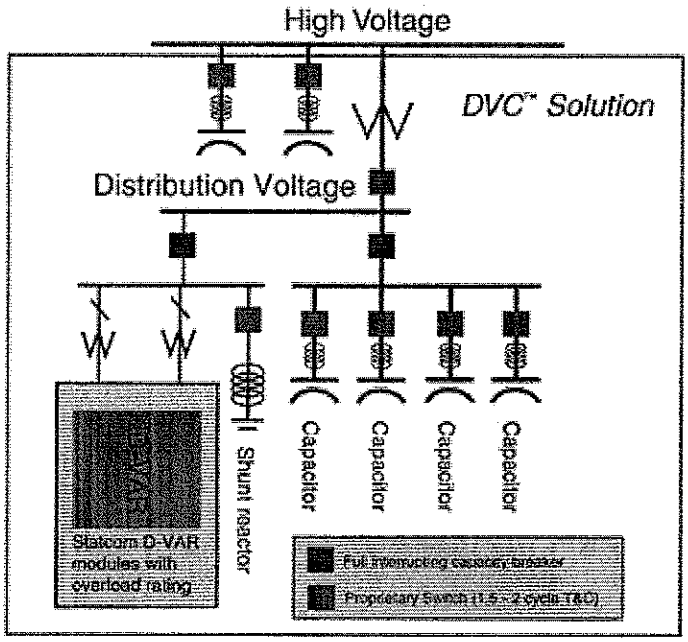
The illustration below shows the basic configuration of a typical DVC solution. The combination of proven inverter-based dynamic VARs and fast-switched shunt elements provides large-scale DVC solutions that have high availability and performance and are more cost effective than STATCOM and SVC solutions. The AMSC D-VAR® modules at the heart of the DVC solution have a proven track record in the field and have performed with the highest of reliability.

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AMSC's PowerModule™ power converters are the building blocks that make up the D-VAR systems that are integrated into the DVC system. These inverters are highly power dense and have transient overload capability which allows the DVC solution to be even more cost effective.

DVC systems are modular and easily expandable to meet ever-changing grid conditions and customer needs. DVC solutions can help address reactive compensation problems for various applications. Some of the applications include:

- Voltage Stability / Voltage Collapse - uncontrolled rapid decline in system voltage

- Steady-state Voltage Regulation - radial line, wind farms

- Import / Transfer Capability Restrictions - limited ability to reliably import, export or transfer power

**Where Can I Get More Information About DVC Solutions?**

AMSC's grid solutions team has decades of experience in utility transmission and distribution planning and will work with you to identify a highly effective, low cost solution that will meet your specific needs and requirements. For more information about DVC systems for a more reliable grid, contact:

American Superconductor
Tim Poor, Director of Sales
8401 Murphy Drive
Middleton, WI 53562
Ph: 608-831-5773
tpoor@amsuper.com

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REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

# Dynamic Reactive Power Compensation

## Utilizing State of the Art Power Electronics Technology

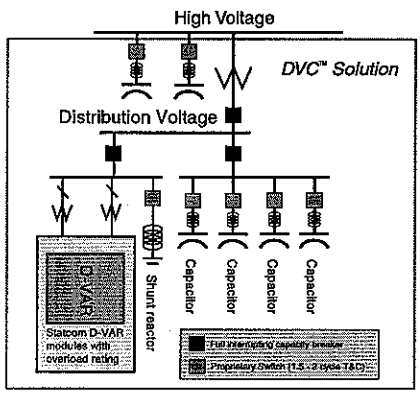
### Benefits

- Hybrid Statcom/SVC technology — Builds off of widely successful D-VAR STATCOM platform
- Modular components — easily expandable
- Less cost than conventional SVC solution

American Superconductor's (AMSC™) DVC (Dynamic VAR Compensators) solutions are based on the widely successful D-VAR® system. They are a hybrid STATCOM/SVC solution that utilizes inverter-based FACTs (Flexible AC Transmission systems) technology similar to D-VAR systems along with proprietary fast-switched capacitors and reactors. AMSC has developed DVC solutions to address the need for large-scale solutions requiring hundreds of megaVARs (MVARs) of reactive compensation.

The DVC systems are modular and scalable. They can be customized to meet any dynamic reactive compensation need and are built in sizes ranging up to several hundred MVAR connected to a single point on the transmission grid.

The illustration shows the basic configuration of a typical DVC solution. The combination of proven inverter-based dynamic VARs and fast-switched shunt elements provides large-scale DVC solutions that have high availability and performance and are more cost effective than STATCOM and SVC solutions. The AMSC D-VAR® modules at the heart of the DVC solution have a proven track record in the field and have performed with the highest of reliability.




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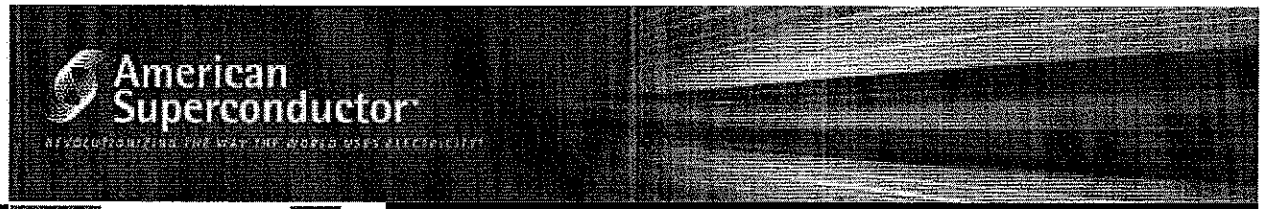
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# Utility

**Flexible AC Transmission Systems (FACTS) for Utility Applications**

As electricity demand continues to rise rapidly, there is an immediate need to increase the quality and reliability of power supplying today's highly complex and digital economy. Environmental concerns, permitting issues and high costs have slowed the expansion and rebuilding of the current power network. Solution options such as FACTS (Flexible AC Transmission Systems) devices can optimize new and existing transmission and distribution lines, making them highly efficient and capable of reliably delivering better quality power to satisfy rapidly growing energy demands.

Some of the benefits of installing a FACTS device include:

- Dynamic reactive power compensation
- Steady-state and transient stability enhancement
- Voltage regulation
- Power transfer capacity increase
- Three-phase voltage balancing
- Reduced transmission losses
- Flicker mitigation
- Oscillation damping

**Static VAR Compensators (SVC)**

American Superconductor (AMSC) is North America's only static var compensator (SVC) manufacturer. AMSC's SVC is a solid-state FACTS device that provides dynamic reactive power compensation based on proven thyristor technology. SVC's can respond to the fastest of voltage transients that appear on power systems and can reduce the risk of detrimental voltage collapse. The vernier control provided by the SVC also allows for steady state voltage regulation, maintaining a smooth voltage profile. AMSC's SVC solutions can be configured to meet specific customer requirements. Our highly experienced power systems engineering team can optimize the SVC configuration to best fit your needs. AMSC provides full turnkey services and offers extensive maintenance and monitoring capabilities. >>More information on AMSC SVC

**D-VAR STATCOMS**

D-VAR® (Dynamic VAR) STATCOMS provide a powerful and

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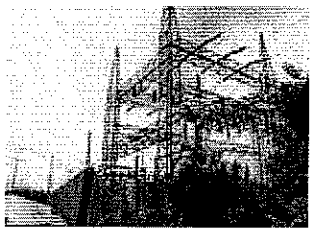
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cost-effective source of dynamic VARs for a wide range of operational needs. D-VAR systems utilize a proprietary and advanced control and monitoring system that detects and instantaneously compensates for voltage disturbances by injecting leading or lagging reactive power. At the heart of each D-VAR system are American Superconductor's (AMSC) PowerModule™ advanced power electronic converters. PowerModule inverters are an intelligent, fully integrated four-quadrant power converter with high power density. D-VAR STATCOMS can respond to voltage events that are both rapid and slow, providing the same level of security, reliability, and enhancement to the grid as an SVC. >>More information on AMSC D-VAR systems

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# Transmission Grid Solutions

**Solutions for Improving Reliability and Security of Transmission Grids**



American Superconductor offers a range of products and services to address the need to make transmission grids more reliable and secure. Our dynamic reactive power grid stabilization products are powerful and economical solutions for addressing grid reliability problems. There are a number of configurations to optimize a transmission reliability system that is best suited to their exact requirements.

At the heart of AMSC's reactive power grid stabilization solutions are AMSC's state-of-the-art PowerModule™ PM1000 advanced power electronic converters for D-VARÂ® systems or AMSC's high temperature superconductor (HTS) rotating machines. Each of these dynamic reactive compensation devices is capable of injecting large amounts of real and/or reactive power to boost voltage on the transmission network within milliseconds.

AMSC works with cable manufacturers to design HTS cable systems to increase power system capcity and expand the "solution space" for grid planners and operators.

**Transmission Planning Expertise**

American Superconductor is a world leader in developing HTS cable projects. AMSC combines knowledge of transmission planning, refrigeration system integration and project execution to provide a seamless transmission solution. AMSC starts with a customer's transmission planning team to determine the best solution for their network. Should an HTS cable be the correct solution, AMSC develops a project specification and works with the cable system and refrigeration system manufacturers to provide solutions on time and within budget.

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**Dynamic Reactive Power Products**

Dynamic reactive compensation devices can be configured to meet a wide range of customer requirements.

**D-VAR®**

AMSC's Dynamic-VAR, or D-VAR®, systems provide dynamic reactive compensation to mitigate low voltage or voltage instability on transmission networks. D-VARÂ units are modular in size, ranging from +/- 1.0 to 8.0 continuous and +/- 3.0 to 24.0 instantaneous MVAR output.AMSC's dynamic reactive compensation devices can:

Eliminate low system voltage / voltage collapse as obstacles to increased load serving capacity (10-50% increase)

Provide both real and reactive power to mitigate voltage stability problems within milliseconds

Defer new transmission line construction until thermal line limits are reached

Because D-VAR systems are mobile assets they can be located exactly where voltage mitigation is needed most in the network.

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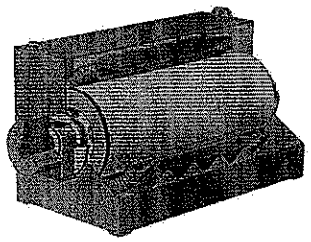
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- TRANSMISSION GRID SOLUTIONS

Applications
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- INDUSTRIAL
- WIND ENERGY
- UTILITY
- SHIP PROPULSION

# Motors, Generators & Synchronous Condensers

## 10 MVAR SuperVAR® Dynamic Synchronous Condenser



The primary function of the 10 MVAR SuperVAR Dynamic Synchronous Condenser (DSC) is to compensate the reactive power on the utility grid. Reactive power, the out-of-phase component of AC power, can be either inductive (voltage leading current, corresponding to inductive reactance) or capacitive (voltage lagging current, corresponding to capacitive reactance). Reactive power does not provide useful energy at the load; however it is a common component of AC power grids and their loads, which are usually inductive but at times can also be capacitive.

Reactive power limits the amount of real power that can be handled on a transmission or distribution grid. A synchronous condenser compensates either an inductive or a capacitive reactance by introducing the opposite type of reactance thus optimizing the useful in-phase power throughput of the grid. The SuperVAR™ condenser design is based on AMSC's proprietary rotating machine design and hardware expertise developed during the last decade.

The SuperVAR design offers a cost-effective alternative to reactive power compensation compared to synchronous generators (the traditional method for compensating reactive power). The DSC allows the generators to operate optimally in producing real power for which a power company is ultimately paid. It is also cost-effective compared to alternatives which use capacitor banks or power electronic systems.

**Specifications**

- 10 MVAR, 13.8 kV at 60 Hertz
- Steady state continuous duty
- Economic source for dynamic VAR support
- Supports transient loads at multiples of machine rating

MOTOR, & SYNCI CONDEN PRODUC
- 10 MVAR

APPLICA MOTORS, & SYNCI CONDEN

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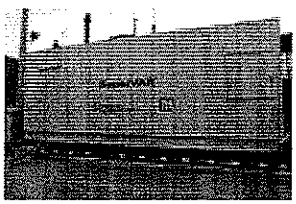
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- High machine operating efficiency
- Long winding life

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# Motors, Generators & Synchronous Condensers

## SuperVAR® Dynamic Synchronous Condensers



American Superconductor's SuperVAR dynamic synchronous condenser is a new, breakthrough product that stabilizes grid voltages, increases service reliability and can help maximize transmission capacity.

Utilities today face an ever-growing demand for higher quality, reliable power and increased transmission capacity. The key to increasing reliability and capacity is ensuring that grid voltage is properly regulated. This helps prevent service disruptions, damage to electrical service equipment, generating plants and other components of the AC power grid and can help maximize transmission capacity. Utilities keep voltage levels stable by maintaining a balance of real power (watts) and reactive power (VARs) on their transmission grids.

American Superconductor's SuperVAR machines are rotating machines, much like motors and generators, and utilize high temperature superconductor technology and serve as reactive power "shock absorbers" for the grid, dynamically generating or absorbing reactive power (VARs), depending on the voltage level of the transmission system.

AMSC's SuperVAR machines use standard synchronous condenser frames and stator coils mated with new, power-dense rotor coils made from AMSC's HTS wire. The result is a synchronous condenser that is more efficient than conventional machines - without the typically high rotor maintenance costs. SuperVAR machines are specifically designed for continuous, steady-state dynamic VAR support while having multiples of their rated output in reserve for transient problems. The HTS rotor enables these machines to provide up to eight times their rated capacity for short periods. AMSC expects to also extend the product line to include units of substantially larger ratings.

**Benefits**

- Transient dynamic voltage support and stability

MOTOR, & SYNCI CONDEN PRODUC
- 10 MVAR

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(leading and lagging VARs) at a multiple of the machines rating

- Economic transmission voltage support and stability improvement
- Increased transmission capacity by reducing transmission losses
- Power factor correction during steady state operation
- Stable operation up to its rated load in either leading or lagging mode
- Minimizes operating power consumption
- Minimizes harmonic content
- Requires less maintenance on machine rotor windings
- Modular transportable design
- Easy installation

**VARs and Reactive Power**

Voltage is the "pressure" that drives electrical current through power lines. Reactive power, which is measured in VARs (volt-ampere-reactive), is the component of electricity that maintains the proper level of voltage in transmission lines to drive "real power," which is measured in Watts, through the power lines to customers.

Reactive power cannot be stored and must be externally supplied to the power grid.

Synchronous condensers share much of their architecture with electric synchronous motors and generators. Their primary function is to stabilize grid voltage by injecting or absorbing reactive power. Reactive power, which can also be understood as the "out-of-phase" component of AC power, can be either lagging (current lagging voltage, corresponding to inductive reactance) or leading (current leading voltage, corresponding to capacitive reactance).

As power demands increase in any AC system, the need for reactive power generally increases. When the transmission grid is forced to deliver large amounts of reactive power over long distances, it can limit the amount of real power that can be generated and delivered across a transmission grid. Therefore, it is advantageous to produce the necessary reactive power close to the loads.

**The HTS Advantage**

By utilizing AMSC's HTS wire, SuperVAR machines provide

a more efficient system with significant advantages over conventional synchronous condensers such as lower standby losses, higher output, lower cost and higher reliability. In addition, the HTS rotor design increases the device's over-excitation and under-excitation output limits to its full-rating without loss of critical clearing time following a transient fault. SuperVAR machines do not experience thermal fatigue of the field coils as the VAR output is varied from no-load to full-load allowing SuperVAR synchronous condensers to be used for peaking as well as base load applications without worries of loss of life due to frequent load changes. These machines do not introduce harmonics into the grid, but do retain high operating efficiency (losses versus VARs) down to 20% of its rated output.

Demand for electric power continues to grow and utilities are looking for ways to leverage their existing grid assets to meet rising customer demand for more reliable power. SuperVAR machines enable existing transmission assets to be operated at higher capacities thereby minimizing the need to construct new power generating facilities or install additional transmission lines in areas of increasing demand. SuperVAR machines can also serve as lower cost replacements for old, polluting inner city Reliability-Must-Run (RMR) generating facilities which are required to operate in order to maintain system reliability and voltage support. The innovative design of SuperVAR synchronous condensers provides a highly efficient alternative to dynamic voltage grid support available from other devices.

**Is SuperVAR® or D-VAR® the Right Solution for my Grid?**

The SuperVAR machine is a new product that complements AMSC's family of reactive power grid stabilization solutions which includes AMSC's D-VAR (dynamic VAR) systems.

- SuperVAR synchronous condensers are specifically designed for continuous, steady-state dynamic VAR support and they maintain a reserve for transient problems.

- D-VAR systems - which are based on AMSC's PowerModule™ power electronic converters - are designed to solve local voltage issues through a controlled, directed output thus addressing more specific existing or known transient problems.

Transmission and distribution grids are complex systems that can require a combination of steady-state dynamic and transient VAR support to ensure reliable power delivery. AMSC's transmission planning and sales teams have decades of experience in the power industry. AMSC works together with utilities and power system operators and conducts extensive studies in order to deliver optimized transmission grid solutions.

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REVOLUTIONIZING THE WAY THE WORLD USES ELECTRICITY™

# Dynamic Reactive Power Compensation

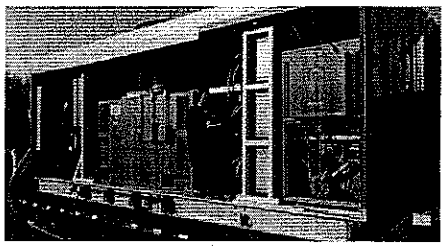
## High Temperature Superconductor Technology

## Benefits

- Provides cost effective, steady state voltage regulation
- Delivers superior transient response
- Improves grid reliability by stabilizing voltage
- Generates/absorbs VARs dynamically
- Mobile version enables quick deployment
- Adds beneficial inertia to system for greater stability
- More compact, lighter and less costly to operate than conventional synchronous condensers
- High efficiency, even under partial loads (down to 0.3 pu)
- Field windings not affected by thermal cycling

### What are SuperVAR Synchronous Condensers?

SuperVAR™ synchronous condensers use High Temperature Superconductor (HTS) technology and can dynamically inject or absorb reactive power (VARs), depending on transmission or distribution system needs.



SuperVAR synchronous condensers serve as reactive power "shock absorbers" for the grid.

SuperVAR systems continuously regulate grid voltages to preserve the desired steady state voltage profile and avoid high or low transient voltages, helping to prevent service disruption and damage to electrical service equipment, generating plants and other components of the AC power grid.

### Operational Description

SuperVAR systems feature a low cost, efficient synchronous HTS rotating machine that helps solve the imbalance between supply and consumption of VARs in order to keep the power system working in an optimum state. SuperVAR systems also add inertia to transmission systems and contribute to overall system stability by acting as a shock absorber for system transients.

SuperVAR systems monitor voltage at the transmission and/or distribution level and depending on the system's need, can dynamically inject or absorb VARs to keep grid voltages within the desired range. SuperVAR systems offer fast-reacting transient dynamic voltage support and can be overloaded at multiples of their ratings for up to 2 minutes.

SuperVAR systems are shunt-connected and have an output of 13.8 kilovolts (kV). SuperVAR systems produce minimal harmonic content and, therefore, require no special filtering.

SuperVAR communication and control systems allow for remote adjustment of voltage set points and can also control multiple shunt capacitors or reactors to expand total dynamic VAR range.

## Specifications

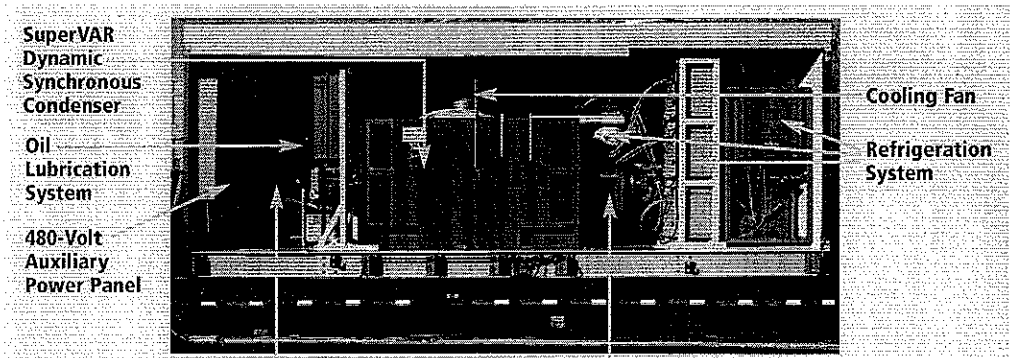
| | |
|---|---|
| Continuous Rating: | ±10 MVAR |
| Transient Overload Rating: | 2 - 8 pu |
| Voltage Rating: | 13.8 kV line to line |
| Losses: | Less than 1.7% of rating |
| Communication: | Remote adjustment of VARs |
| Connections: | NEMA enclosures |
| Auxiliary Power: | 480V, 3-phase, 75 kW |
| Design Standards: | IEE/ANSI C50.13-2002 |
| Dimensions: | Typically 8' x 10' x 24' |
| Other: | System packaged in enclosure<br>Minimal on-site installation<br>Contains all auxiliary systems<br>Remote monitoring<br>Self-protecting |

## Product Applications

SuperVAR Dynamic Synchronous Condensers help alleviate voltage problems in many applications including:

- Reactive Compensation - Transmission and Distribution Systems
- Steady State Voltage Regulation - Long Radial Delivery Systems
- Dynamic Power Factor Correction - Large Industrial Sites
- Flicker Mitigation for Sensitive Power Quality - Steel Mills, Mines, Arc Furnaces

The first SuperVAR synchronous condenser (rated at ±8 MVAR) is being used by the Tennessee Valley Authority to mitigate voltage flicker at a steel mill in Gallatin, Tennessee




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# Superconducting Dynamic Synchronous Condenser For Improved Grid Voltage Support

Swarn Kalsi, David Madura, Ray Howard, Greg Snitchler and Tim MacDonald
and
Dale Bradshaw, Ian Grant and Mike Ingram

*Abstract*-- **Synchronous condensers are an attractive source of dynamic VARs (both inductive and capacitive) to improve system stability and maintain voltages under varying load conditions and contingencies. A synchronous condenser is a rotating machine that runs synchronized with the grid. Its field is controlled with a voltage regulator to either generate or absorb reactive power as needed by the power system. American Superconductor Corporation's (AMSC) proprietary SuperVAR™ Dynamic Superconducting Condenser (DSC) machines upgrade existing technology by using a conventional armature mated with a field winding made from High Temperature Superconducting (HTS) wires. The result is a DSC that is both more efficient and has lower maintenance than conventional machines. It can provide up to 8 pu current for short periods to support transient VAR requirements. The Tennessee Valley Authority (TVA) is sponsoring the development and field testing of an 8 MVAR prototype unit to be followed by five 10 MVAR production units. Larger units are planned for the future. This paper describes features of the DSC and its performance in grid applications.**

*Index Terms*—**Superconducting motors and generators, High temperature superconductors, Superconducting rotating machines, Synchronous condensers, Superconducting condensers**

## I. Nomenclature

HTS – High Temperature Superconductors
LTS – Low Temperature Superconductors
DSC - Dynamic Superconducting Condenser
BSCCO – First-generation HTS superconductors
DVAR - A statcom applied at distribution voltage, may include energy storage
FACTS - Flexible AC transmission systems

## II. Introduction

Dynamic VARs are an important requirement for increasing the electric loading of transmission lines. While static capacitors are widely used, a dynamic response is often essential to maintain dynamic and voltage stability and prevent voltage collapse. Superconducting synchronous condensers are expected to be a lower cost and more reliable device and thus superior to FACTS devices in this application.

The following quote from a paper by Prof. Wollenberg[i] summarizes the importance of VARs in a grid - *"...But why should we want to transmit reactive power anyway? Is it not just a troublesome concept, invented by the theoreticians, that is best disregarded? The answer is that reactive power is consumed not only by most of the network elements, but also by most of the consumer loads, so it must be supplied somewhere. If we can't transmit it very easily, then it ought to be generated where is needed."*

Reactive power does not provide useful energy at the load (useful energy is supplied by the in-phase component); however it is a common component of AC power grids and their loads which are usually inductive but at times can be capacitive too. Over a given AC line, as power demand increases the need for reactive power increases more rapidly as shown in Figure 1 for a 200 km long 500 kV transmission line with 1000 MW Surge Impedance Loading (SIL) . Lack of reactive support can limit the amount of real power that can be delivered across a transmission grid and cause congestion, resulting in Transmission line Loading Relief calls (TLRs). It is advantageous to produce the necessary reactive power close to the loads. This applies equally for both static and dynamic VARs.

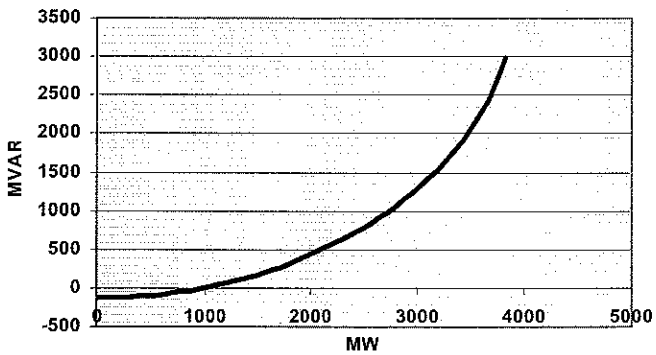



Figure 1: MVARs requirement increases rapidly as real power on the sending end increases

## III. Performance Features

A synchronous condenser shares much of its architecture with electric synchronous motors and generators. Its primary function is to compensate the reactive power on the grid.

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Reactive power, the out-of-phase component of AC power, can be either lagging (current lagging voltage, corresponding to inductive reactance) or leading (current leading voltage, corresponding to capacitive reactance).

A DSC is capable of generating or absorbing reactive power (MVARs) at needed locations on a power grid. DSC machines are inherently capable of continuous steady-state as well as dynamic reactive compensation while having multiples of their rated output in reserve for transient events. DSC units with superior dynamic capabilities can be applied throughout the grid to supply or absorb VARs as needed.

Table 1 compares DSC with other competing products. Key benefits of a DSC are summarized as follows[ii]:

- Fast reacting transient dynamic voltage support and stability (leading and lagging VARs) at a multiple of the machines rating
- Fully capable of either leading or lagging VARs mode
- Low losses
- Low maintenance and high reliability
- Does not generate harmonics
- Simple installation
- Can be manufactured for 13.8 kV and higher voltage ratings
- Easily made resistant to poor quality or lost auxiliary power including severe voltage sags
- Contains virtually no environmentally sensitive materials (small quantities of lubricating oil)

By utilizing the current-generation HTS wire (BSCCO-2223), DSC machines provide[iii] a more efficient system with significant advantages over conventional synchronous condensers such as lower standby losses, higher output, lower cost and higher reliability. In addition the HTS rotor design increases the device's over-excitation and under-excitation output limits to full-rating without loss of critical clearing time following a transient fault. DSC machines do not experience thermal fatigue of the field coils as the VAR output is varied from no-load to full-load. Thus DSC synchronous condensers can be used for peaking as well as base load applications without loss of life due to frequent load changes. These machines do not introduce harmonics into the grid, and do retain high operating efficiency (losses versus VARS) down to 20% of their rated output.

TABLE 1: COMPARISON OF SUPERVAR™ DSC WITH OTHER COMPETING TECHNOLOGIES

| Functional Characteristics | Capacitors | STATCOM | SVC | D-VAR | SuperVAR DSC |
|---|---|---|---|---|---|
| Solution type | Steady-state | Steady-state and Dynamic | Steady-state and Dynamic | Steady-state and Dynamic | Steady-state and Dynamic |
| Continuous VARS output | Leading | Leading / Lagging | Leading / Lagging | Leading / Lagging | Leading / Lagging |
| Inherent transient overload rating | No | No | No | 3x | up to 8x nominal |
| Real power output | None | None | None | Optional | None |
| Response to transient events | Slow | Sub-cycle | Sub-cycle | Sub-cycle | Sub-cycle |
| Response to severe (deep) voltage dips | No | Sub-cycle | No | Sub-cycle | Sub-cycle |
| Ability to control other devices | None | Yes | Yes | Yes | Yes |
| Independent phase control | None | Yes | None | Yes | None |
| Discretely controlled output | No | Fast | Fast | Fast | Slow |
| Harmonic compensation required | Application dependent | Yes | Yes | Application dependent | No |
| Creation of over voltage spikes | Yes | No | No | No | No |
| Output dependent on bus voltage | Decreases with square of voltage | Decreases linear with voltage | Decreases with square of voltage | Decreases linear with voltage | Independent of bus voltage |
| Efficiency | 99% | 98-99% | 98-99% | 98-99% | 98-99% |
| Foot print | Small | Medium | Large | Small | Small |
| Ease of installation | Simple | Complex | Complex | Simple | Simple |
| Cooling | Ambient air | Liquid | Liquid | Ambient air | Air/Liquid |
| Availability and delivery time | 6 months | 12 months | 12 months | 6 months | 6 months |
| Losses | Low | High | Medium | Low | Low |
| Inertia adds to system stability | No | No | No | No | Yes |

The HTS field winding is maintained at essentially constant temperature for all levels of field current. The stationary reference frame employs refrigeration elements which are high-reliability devices available from other applications. On the other hand in a conventional machine, the field winding current typically varies from 1 to 3 pu which changes conductor temperature. As a result of this conductors experience significant thermal expansion which causes mechanical fatigue of the insulation leading to eventual failure.

*Sensitivity to Auxiliary Voltage*

An important issue that is often overlooked and which directly affects reliability is the auxiliary supply to FACTs devices. Supply for control equipment, electronics devices, and cooling is often obtained directly from the same voltage source that the FACTs device is supporting. When a fault occurs, poor quality of the auxiliary supply to the FACTs equipment may trip the device at exactly the moment that it is needed. A DSC is largely immune to this concern, since its refrigeration equipment has significant thermal inertia and its control equipment has a low load and can easily be supported on a small UPS.

## IV. Design Configuration

The major components of a DSC are shown in Figure 2. Only the field winding employs HTS windings cooled with a cryocooler subsystem to about 35-40K. The cryocooler modules are located in a stationary frame and a fluid such as gaseous helium or liquid neon is employed to cool components on the rotor. The stator winding employs conventional copper windings.

Cooling systems have been developed for cooling HTS field windings to 30 K. These systems employ Gifford-McMahon (GM) cryocoolers, which are the same components widely used by MRI and vacuum system industries and are available as catalog items with a high implicit reliability. There is substantial operating experience with both HTS field windings and cryocooling systems. A typical cryocooler and its compressor are shown in Figure 3 with cryocooler heads about 4-in diameter and 14-in tall. A typical compressor is a cube with 24-in side dimension weighing about 260 lbs that could be located remotely from the machine if desired, for example to simplify maintenance access outside the high voltage area. For the prototype, compressors will be cooled with a closed cycle water circuit, and the DSC stator and compressor will be air-cooled.

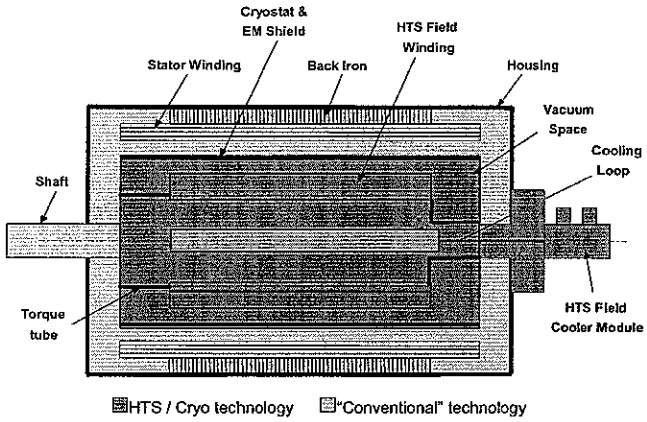



Figure 2: Block diagram of a DSC synchronous machine showing superconducting field winding and its cooling system and conventional armature winding

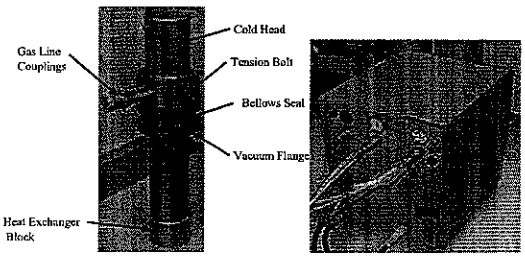



Figure 3: A cryocooler (left) and its compressor (right)

*Prototype Details*

A prototype DSC presently being manufactured for TVA will have an 8 mega-VAR (MVAR) continuous rating. The DSC is rated for 13.8 kV line to line voltage.. The machine employs a closed loop cryogenic system and a brushless exciter. The DSC is shown in Figure 4. For a short-circuit fault at the machine terminals it can deliver short-circuit current of 8 pu (first peak) and an average of 6.5 pu over the first 5 cycles. This machine will also withstand a 2 pu current loading for up to 60 seconds. The machine is designed to operate in an ambient temperature of -30°C to +40°C in an outdoor installation. The prototype will be locally and remotely monitored for adjusting VAR loading and for its electrical, mechanical and thermal states.

Prior to installation of the prototype a detailed PSS/E model (just developed) will be used in a system simulation to enable optimum setting of the controls and to predict the system behavior with the unit. It is presently planned to operate the prototype in the field for 12 months in a location close to an arc furnace that will provide essentially continuous dynamic operation of the unit.

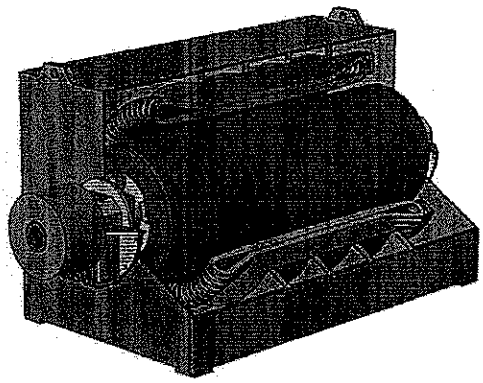


Figure 4: DSC employs superconducting field winding and conventional stator

The DSC is expected to have a life expectancy of over 30 years and should have 50% less losses than conventional synchronous condensers.

The DSC design being developed for TVA is based on a successful demonstration of an HTS superconducting motor[v] (5,000 HP, 1800-RPM) in July 2001. The motor shown in Figure 5 undergoing factory testing was tested up to 5,900 hp (steady-state) in the fall of 2001. Similar confidence in the technology comes from a 70 MVA generator employing low temperature superconductors has been demonstrated[vi] by Hitachi in Japan, where it was demonstrated that it could be operated at 100% of its rated capacity and zero power factor (70 MVARs) without overheating.

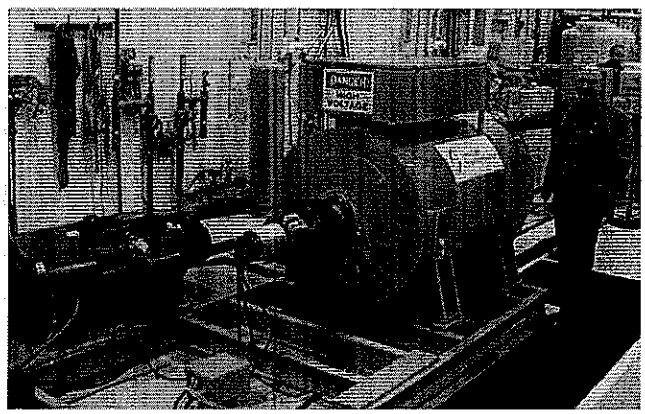


Figure 5: A 5,000 hp, 1800-RPM HTS motor undergoing testing in 2001

The prototype DSC will be housed in an ISO container 8ft wide x 8ft tall x 20ft long. It will weigh 40,000 lbs., which includes the DSC, its support equipment, and the ISO container. It is expected that DSCs would normally be pad mounted but for convenience the TVA prototype will be installed on a trailer. The prototype requires about 30 kW of auxiliary power and this will be obtained from a dry-type transformer connected to the 13.8 kV station bus. Later production units will employ a single cryocooler rather than three as in the prototype.

## V. Operational Features

The DSC has low synchronous reactance ($x_d$ = 0.5 pu) which assures dynamic stability within its MVA rating and provides better voltage regulation than a conventional machine. The benefits of lower $x_d$ are summarized below:

- The superconducting machines exhibit lower voltage difference between no-load and full-load operations
- The voltage (E) behind the synchronous reactance is only 1.5 pu at the rated load at zero pf (lagging – over-excited). Since E is proportional to the field current, the DSC will experience a maximum of only 50% field current change as compared to 200% change in a conventional machine.
- E is 50% less than that in a conventional machine.

The sub transient reactance ($x_d$") of the machine is also low (0.11 pu) which lets the machine provide up to 8 pu first peak current for a terminal short circuit. The major parameters of the machine are shown in Figure 6.

Figure 7 compares the efficiency of the DSC with a conventional synchronous condenser. The HTS field winding eliminates 50% of conventional machine field losses which provides improved efficiency. Additional efficiency is made possible through windage reductions. The DSC also generates very low harmonics. Total Harmonic Distortion (THD) is less than 2.3%.

| | |
|---|---|
| Synchronous reactance ($x_d$), pu | 0.5 |
| Transient reactance ($x_d$'), pu | 0.22 |
| Sub-transient reactance ($x_d$"), pu | 0.11 |
| Sub-transient reactance ($x_q$"), pu | 0.12 |
| Armature short-circuit time constant ($\tau_{ac}$), s | 0.045 |
| D-axis Transient short-circuit time constant ($\tau_d$'), hr | 7.31 |
| D-axis Sub-transient short-circuit time constant ($\tau_d$"), s | 0.01 |
| D-axis Transient open-circuit time constant ($\tau_{do}$'), hr | 15.55 |
| D-axis Sub-transient open-circuit time constant ($\tau_{do}$"), s | 0.02 |
| Q-axis Sub-transient short-circuit time constant ($\tau_q$"),, s | 0.011 |
| Q-axis Sub-transient open-circuit time constant ($\tau_{qo}$"), s | 0.043 |
| Armature resistance ($r_a$), pu | 0.007 |
| Inertial constant, s | 1.55 |

Figure 6: Performance parameters of the DSC

### Performance

The DSC has no dynamic stability limit within its MVA rating. The machine can run stably without requiring any feedback control for dynamic voltage stabilization. This machine also has a superior dynamic stability during small oscillations and requires no field forcing for damping such oscillations. Figure 8 shows its damping of oscillations following a sudden change of load.

DSC transient stability was studied using a single machine model shown in Figure 9. A 10 MVAR machine was connected to a station bus through a 0.02 pu impedance transformer (assumed model for a 100 MVA station transformer). The substation in turn was connected to a remote bus through two transmission lines with 0.063 pu and 0.19 pu impedances (on a 10 MVA base). Prior to the fault the machine was assumed to be synchronized with the

grid. A 3-phase fault was assumed on the high voltage side of the transformer on the 0.063 pu line. Recovery of the DSC from 3-phase faults is shown in Figures 10 through 13. Further studies are underway with the new PSS/E model.

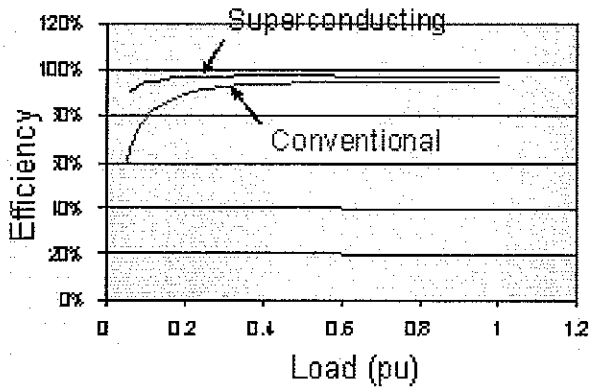



Figure 7: DSC versus conventional machine efficiency

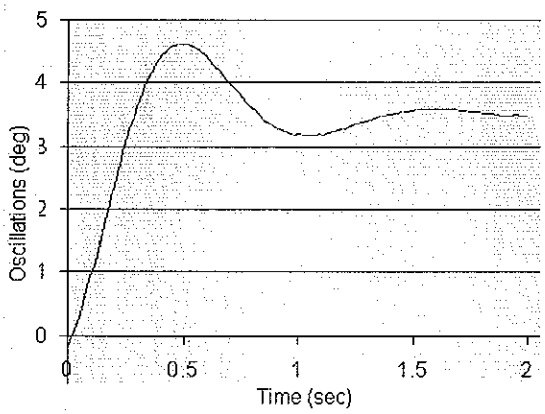



Figure 8: DSC damping of low frequency oscillations following a sudden load change

Figure 10 shows the recovery of a DSC from a fault on the high voltage side of the transformer. The fault duration was 25 cycles. Well-damped rotor oscillations in Figure 10 confirm that this machine can recover from such a fault. The 25 cycle fault duration is much longer than the time needed by a typical protection system to clear a fault.

The current during the fault and recovery periods is shown in Figure 11. In order to obtain a symmetrical fault current waveform the fault was assumed to occur at the peak of armature phase-A voltage. The first peak of the phase A fault current is ~ 8 pu with an average of 6 pu for the first 5 cycles. Fault current settled to about 4 pu for the remainder of the fault period. During a fault the machine slows down, and once the fault is cleared it must draw energy from the grid to recover lost speed. The machine draws about 5 pu current (1st peak) after the fault is cleared and returns to its pre-fault current level in about a second.

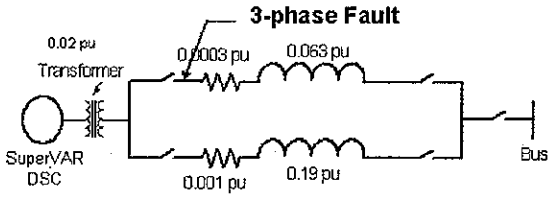



Figure 9: A DSC connected to a remote bus through a dual transmission line for fault studies

Machine terminal voltage during pre-fault, fault and post-fault periods is shown in Figure 12. The machine terminal voltage before the fault is nominal 1.0 pu. In this state the machine was connected to the grid but supplies no current. During the fault machine terminal voltage was depressed to 0.1 pu. Once the fault was cleared, the machine terminal voltage started to recover and achieved its pre-fault level in about a second. This voltage recovery was achieved without any change in the field excitation.

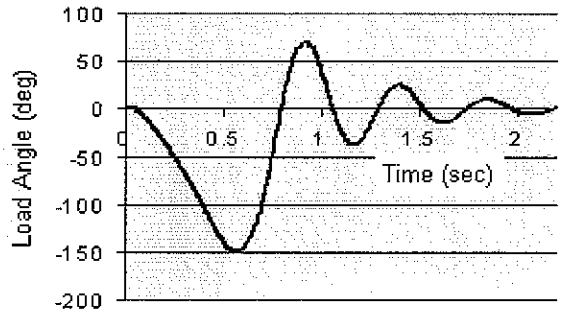



Figure 10: Load angle swing due to a 25 cycle fault on the high voltage side of the transformer

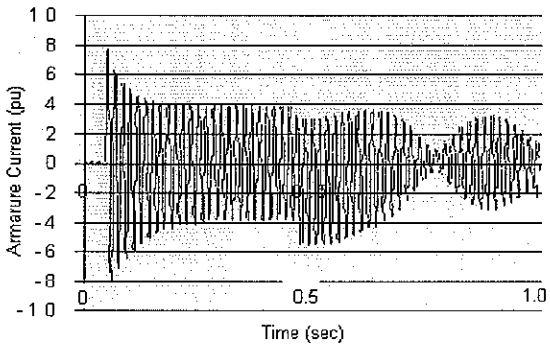



Figure 11: DSC contributes 6 pu current (average) to the fault during a fault and once the fault is cleared, it draws 5 pu current from the grid to make up the lost speed

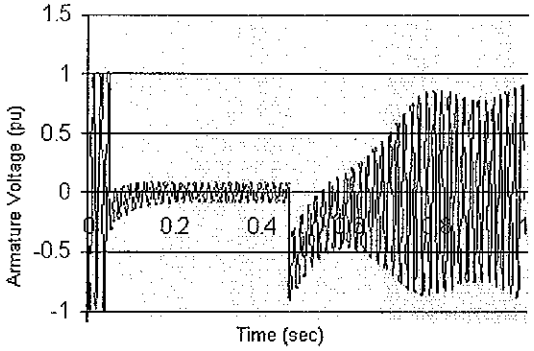



Figure 12: DSC recovers its terminal voltage in about a second without requiring adjustment of the field current

The DSC synchronized with the grid required 1.0 pu field current when delivering no stator current. However, during a fault the armature reaction raised the field current to 2.0 pu. Once the fault was cleared the field current returned to its pre-fault value in about a second. This field current behavior is shown in Figure 13.

These fault studies were also conducted when the machine was delivering its full rating (lagging or leading VARs). Figure 14 summarizes results of these studies. It shows maximum fault duration from which the machine can recover for the following three cases;

- machine initially absorbing VARs (under-excited),
- machine initially delivering no current, and
- machine initially generating VARs (over-excited).

The DSC recovered from a 23 cycle fault while carrying rated MVAR loading – lagging or leading. Its contribution to the fault current (5 cycle average) was higher than 6.6 pu in the over-excited mode as compared to 4.9 pu for the under-excited mode.

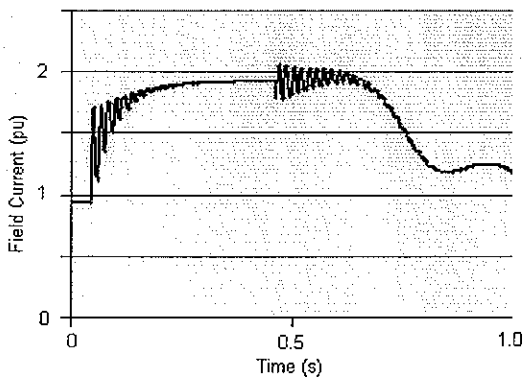



Figure 13: Field current experiences changes due to armature reaction during fault and post-fault periods, but returns to its pre-fault value in about a second

| Pre-Fault Condition | MVARS Loading | Fault Duration (Cycles) | Field Current (pu) | Fault Curret (pu) Fist Peak | Average of first 5-peaks |
|---|---|---|---|---|---|
| Under-Excited | -8 | 23 | 0.5 | 7.1 | 4.9 |
| No current | 0 | 25 | 1 | 7.7 | 5.7 |
| Over-excited | 8 | 23 | 1.5 | 8.5 | 6.6 |

Figure 14: DSC recovers from 23-cycle faults when delivering rated MVAR (lagging or leading)

If the DSC were required to start direct-on-line, the machine would take about 12 seconds from standstill to achieve rated speed. During this period it would draw a starting current of 5.7 pu., assuming a 0.02pu impedance supply transformer.

If a DSC were subjected to a 3-phase terminal fault that cannot be cleared then it would be necessary to remove the field excitation in order to protect the machine. The machine would otherwise continue to deliver 4 pu current into the fault for a long period of time. In such a situation the DSC protection system must de-excite the field winding. The field current can be reduced to an insignificant value in about 6 seconds limiting total energy deposited in the armature winding to about 2 MJ. This energy is absorbed by the armature with an adiabatic temperature rise of about 10°C.

## VI. Conclusions

The innovative design of the DSC is believed to offer a highly efficient low cost alternative for dynamic VAR supply. A prototype unit of 8 MVAR rating is being constructed for TVA, to be followed by 5 10 MVAR units. Units of larger ratings (100-300 MVAr) are expected to be built in the future.

## VII. Acknowledgements

The authors acknowledge support of the Tennessee Valley Authority for the development of the DSC. They also acknowledge the support of the AMSC SuperMachines Business Unit engineering and technical staff.

## VIII. References

[i] Wollenberg, B.F., 'Transmission system reactive power compensation', Presented at IEEE Power Engineering Society meeting, New York, January 2002

[ii] Miller, T. J. E., 'Reactive Power Control in Electric Systems', John Wiley & Sons, 1982

[iii] SuperVARTM Dynamic Synchronous Condensers, http://www.amsuper.com/html/products/motorsgenerators/quickvar.html

[v] Gamble, B., et al, 'Status of HTS motors', Presented at IEEE Power Engineering Society meeting, Chicago, July 2002

[vi] K. Yamaguchi, et al, '70 MW Class Superconducting Generator Test', IEEE Transactions on Applied Superconductivity, Vol. 9, No. 2, June 1999, page 1209

## APPENDIX 11
## HYDRO EMAILS – FINANCIAL MODEL INPUT INFORMATION

# APPENDIX 11
# HYDRO EMAILS – FINANCIAL MODEL INPUT INFORMATION

# HYDRO Email No. 1

## Hearn, Bill G.

**From:** AndreaMacDonald@nlh.nl.ca
**Sent:** Friday, October 26, 2007 12:31 PM
**To:** Hearn, Bill G.
**Cc:** NSeymour@nlh.nl.ca
**Subject:** Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Further info regarding annual forecasted MWhrs. Please see the attached e-mail. Thanks.

Andrea

Andrea MacDonald, P. Eng.
Engineering Services - Mechanical
Newfoundland and Labrador Hydro
PO Box 12400
St. John's, NL A1B 4K7
www.nlh.nl.ca
Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/26/2007 12:58 PM -----

**Art Bursey/NLHydro**
10/26/2007 11:12 AM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject Re: Fw: Request for Stats for Hardwoods and Stephenville GT's Info Link

Andrea,

The forecast average MWhrs loading for the gas turbine for the next 15 years is a very variable number as the future requirements of the gas turbine will change depending upon a number of factors. Our forecast uses a value of 100 MWhrs monthly or 1200 MWhrs yearly. The past five years show the average MWhrs is closer to 300 to 600 MWHrs.

In the forecast the units for energy is giga watt hours (1000 MWhrs). This would make the average 1.2 GWhrs and the past five year average of 0.6 GWHrs, which is approximately 1 GWHrs.

I would recommend that we could use the 1.2 GWhrs or 1200 MWhrs value for both Hardwoods and Stephenville, but make reference that this number could change significantly over the next 15 years.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services

Newfoundland & Labrador Hydro

Phone (709) 737-1395
Fax (709) 737-1318
e-mail: abursey@nlh.nl.ca

**Andrea MacDonald/NLHydro**

10/17/2007 09:00 AM

To Art Bursey/NLHydro@NLHydro
cc
Subject Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Hi Art,

For the Stephenville gas turbine facility: if we take the average MWhrs for the last 5 years and use that as the average power every 5 years for the next 15 years, how accurate will this be? Please advise. Thanks.

Andrea

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----- Forwarded by Andrea MacDonald/NLHydro on 10/17/2007 08:57 AM -----

**Nelson Seymour/NLHydro**

10/16/2007 05:09 PM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject Re: Fw: Request for Stats for Hardwoods and Stephenville GT's Info Link

I suggest we use the average for Hwds as you proposed. Not so sure about Svl and the estimated effect that the closing of the paper mill will have. Consult with Art Bursey to get his thoughts.

Nelson

**Andrea MacDonald/NLHydro**

10/16/2007 10:53 AM

To Nelson Seymour/NLHydro@NLHydro
cc
Subject Fw: Request for Stats for Hardwoods and Stephenville GT's Info

Hi Nelson,

From the attached information from operations, N&G has noted that the MWhrs vary greatly from year to year. Over the 5 year span, the numbers vary from a low of 115 MWhrs in 2004 to a high of 1123 MWhrs in 2003. Should they use the 5 year average for their life cycle analysis for the next 15 years? If not, what do you suggest?

Please advise.
Thanks.

Andrea

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----- Forwarded by Andrea MacDonald/NLHydro on 10/16/2007 10:48 AM -----

**Art Bursey/NLHydro**

10/15/2007 03:47 PM

To Hughie Ireland/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject Re: Request for Stats for Hardwoods and Stephenville GT's InfoLink

Hughie,

Questions are answered below in red.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services
Newfoundland & Labrador Hydro

Phone (709) 737-1395
Fax (709) 737-1318
e-mail: abursey@nlh.nl.ca

**Hughie Ireland/NLHydro**

10/10/2007 11:25 AM

To Art Bursey/NLHydro@NLHydro
cc Steve Carter/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro, Andrea MacDonald/NLHydro@NLHydro
Subject Request for Stats for Hardwoods and Stephenville GT's Info

As a result of the ongoing project to complete a condition assessment of HWD and SVL GTs , the consultant N&G have requested the following information with the hope to receive this by the middle of next week in order for them to maintain their current project schedule.

1. Annual MWhrs for each year for the last 5 years for each site.

| | Hardwoods | Stephenville |
|---|---|---|
| | Gross MWhrs | Gross MWhrs |
| 2002 | 245 | 14 |
| 2003 | 1,123 | 785 |
| 2004 | 115 | 36 |
| 2005 | 612 | 194 |
| 2006 | 1,116 | 706 |

2. Synchronous Condenser Operating hours last 5 years for each site.

HWD - 15,512.67 hours
SVL - 4,799.20 hours

3. Number of failed starts/stops last five years for each end at each site.( If not by end then by site will be acceptable)

HWD - 7
SVL - 5

4. Number of successful start/stops in last five years for each end at each site. ( If not by end then by site will be acceptable)

HWD - 127
SVL- 72

The data above is for the period of January 1, 2002 to Decmeber 31, 2006

Thanks

Hughie

----- Forwarded by Hughie Ireland/NLHydro on 10/10/2007 10:29 AM -----

**Andrea MacDonald/NLHydro**

10/10/2007 09:38 AM

To James Wheeler/NLHydro@NLHydro
cc Hughie Ireland/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro, Nelson Seymour/NLHydro@NLHydro
Subject Re: Fw: Hardwoods and Stephenville GT's InfoLink

Hi Jim,

I've reviewed the X drive information. The only thing missing is the semi-annual inspection data for Hardwoods.

New information arising from Aug 21 2007 meeting:

As per the minutes (attached), N&G has requested operational data. Please see item 5 - Operational Data - Hardwoods and Stephenville (pages 8 and 9).

Please let me know whether or not this information is something that we can supply.

Thanks.

Andrea
[attachment "2007-09-05 - Hardwoods GT Kick-off Meeting Minutes.pdf" deleted by Andrea MacDonald/NLHydro]

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**James Wheeler/NLHydro**

10/09/2007 09:09 PM

To Hughie Ireland/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro, Steve Carter/NLHydro@NLHydro
Subject Re: Fw: Hardwoods and Stephenville GT's InfoLink

I haven't done much with the latest request. I can't access the x: drive where the data was located for Andrea to find and pass on to N & G. I remember populating the fields with all the data we were able to find at the time.

Andrea / Steve:
Could you review the information on the X: drive and determine if there is anything else we can get. Other items like run hours, run mode and start / stops would have to be addressed by the operators in conjunction with maybe the ECC. Steve, would you supply to Andrea whatever information the operators may have logged. There may be other items listed on pages 7 and 8 of Nelson's Sept 5 email.

Hughie:
You are the only person who can supply any information on the financial side.

Jim

**Hughie Ireland/NLHydro**

10/09/2007 02:55 PM

To James Wheeler/NLHydro@NLHydro
cc
Subject Fw: Hardwoods and Stephenville GT's

Have you done anything with this request ? I will handle the request regarding the budget.

Regards,

Hughie

----- Forwarded by Hughie Ireland/NLHydro on 10/09/2007 02:54 PM -----

**Andrea MacDonald/NLHydro**

10/05/2007 12:26 PM

To Hughie Ireland/NLHydro@NLHydro
cc Nelson Seymour/NLHydro@NLHydro
Subject Fw: Hardwoods and Stephenville GT's

Hi Hughie,

Please see the attached e-mail. Since Jim is on vacation, perhaps you could assist us with gathering this information? Thanks.

Andrea

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----- Forwarded by Andrea MacDonald/NLHydro on 10/05/2007 12:25 PM -----

**Andrea MacDonald/NLHydro**

10/02/2007 04:23 PM

To James Wheeler/NLHydro
cc
Subject Hardwoods and Stephenville GT's

Hi Jim,

Please advise whether information will be soon available on the following items or whether no information could be found:

1. Operational Data - Hardwoods and Stephenville. (page 8 of the minutes dated Aug 21, 2007, and e-mailed on Sept 5 2007 by Nelson)

2. Semi-annual inspections for Hardwoods (page 7 of the minutes dated Aug 21, 2007)

Thanks very much.

Andrea

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# HYDRO Email No. 2

## Hearn, Bill G.

**From:** AndreaMacDonald@nlh.nl.ca
**Sent:** Friday, November 02, 2007 9:16 AM
**To:** Hearn, Bill G.
**Subject:** Fw: Gas Turbine MVARS for each site
**Follow Up Flag:** Follow up
**Flag Status:** Blue
**Attachments:** GT Loading.xls

Bill,
Please see the attached file for the requested information on gas turbine site MVARS.

Andrea

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Phone: 709-737-1205
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----- Forwarded by Andrea MacDonald/NLHydro on 11/02/2007 09:43 AM -----

**Art Bursey/NLHydro**

11/02/2007 09:38 AM

To James Wheeler/NLHydro@NLHydro
cc Andrea MacDonald/NLHydro@NLHydro
Subject Re: Fw: Gas Turbine QuestionLink

Jim,

Please refer to the attached spreadsheet with the daily average and maximum MVAR for Hardwoods and Stephenville Gas Turbines from June 10, 2006 to Nov 1, 2007.

Thanks,

Art

Art Bursey
Senior System Operations Engineer
System Operations & Customer Services
Newfoundland & Labrador Hydro

Phone (709) 737-1395
Fax (709) 737-1318
e-mail: abursey@nlh.nl.ca

**James Wheeler/NLHydro**

10/31/2007 11:38 AM

To Art Bursey/NLHydro@NLHydro
cc
Subject Fw: Gas Turbine Question

Art:
Could you let me know what the typical daily and maximum MVAR load is for both HWD and SVL GT's.

Thanks
Jim

----- Forwarded by James Wheeler/NLHydro on 10/31/2007 11:06 AM -----

**Andrea MacDonald/NLHydro**

10/31/2007 10:35 AM

To James Wheeler/NLHydro@NLHydro
cc
Subject Gas Turbine Question

Hi Jim,

Neill and Gunter has one last question regarding the gas turbine sites:

What is a typical (any given day) MVAR load for each of the GT sites. In addition, what would be the Maximum MVAR load experienced at each site.

Please forward this information to be. If it is not possible to obtain, please let me know that as well.

Thanks.

Andrea

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**Hardwoods**

| | Daily Average MVAR | Daily Max MVAR |
|---|---|---|
| June 10, 2006 | -1.40 | 15.45 |
| June 11, 2006 | -3.27 | 6.45 |
| June 12, 2006 | 4.37 | 15.36 |
| June 13, 2006 | -7.77 | 13.92 |
| June 14, 2006 | -4.49 | 9.51 |
| June 15, 2006 | 0.17 | 15.18 |
| June 16, 2006 | -3.25 | 14.19 |
| June 17, 2006 | 0.38 | 9.06 |
| June 18, 2006 | 7.34 | 18.24 |
| June 19, 2006 | 3.91 | 14.55 |
| June 20, 2006 | 2.33 | 20.04 |
| June 21, 2006 | 2.51 | 15.01 |
| June 22, 2006 | 1.07 | 18.96 |
| June 23, 2006 | 6.37 | 17.52 |
| June 24, 2006 | 3.90 | 16.89 |
| June 25, 2006 | -0.02 | 10.23 |
| June 26, 2006 | -4.01 | 18.33 |
| June 27, 2006 | 2.42 | 17.54 |
| June 28, 2006 | 0.23 | 12.03 |
| June 29, 2006 | -2.45 | 12.48 |
| June 30, 2006 | 9.31 | 23.37 |
| July 1, 2006 | 2.50 | 12.84 |
| July 2, 2006 | 0.04 | 13.02 |
| July 3, 2006 | -0.24 | 21.39 |
| July 4, 2006 | 1.32 | 22.38 |
| July 5, 2006 | -3.51 | 11.76 |
| July 6, 2006 | -9.16 | 9.15 |
| July 7, 2006 | -2.26 | 13.29 |
| July 8, 2006 | 5.19 | 11.31 |
| July 9, 2006 | 0.93 | 11.76 |
| July 10, 2006 | -1.84 | 10.59 |
| July 11, 2006 | 10.85 | 21.30 |
| July 12, 2006 | -3.08 | 9.69 |
| July 13, 2006 | 3.51 | 11.58 |
| July 14, 2006 | -6.40 | 4.29 |
| July 15, 2006 | -4.96 | 12.66 |
| July 16, 2006 | -9.50 | 8.34 |
| July 17, 2006 | -2.08 | 10.05 |
| July 18, 2006 | 1.74 | 16.17 |
| July 19, 2006 | 7.07 | 21.84 |
| July 20, 2006 | 3.55 | 11.49 |
| July 21, 2006 | 2.72 | 6.18 |
| July 22, 2006 | 5.15 | 15.63 |
| July 23, 2006 | -1.74 | 18.33 |
| July 24, 2006 | -9.73 | -3.17 |
| July 25, 2006 | -4.19 | 6.36 |
| July 26, 2006 | -1.01 | 4.74 |
| July 27, 2006 | 0.06 | 0.06 |
| July 28, 2006 | 0.06 | 0.06 |
| July 29, 2006 | 4.09 | 17.34 |
| July 30, 2006 | 7.74 | 18.06 |
| July 31, 2006 | 2.93 | 15.64 |
| August 1, 2006 | 0.13 | 12.48 |
| August 2, 2006 | -2.59 | 0.15 |
| August 3, 2006 | -0.82 | 15.81 |
| August 4, 2006 | 1.52 | 16.44 |
| August 5, 2006 | -3.78 | 7.71 |
| August 6, 2006 | -0.70 | 8.25 |
| August 7, 2006 | -8.09 | 12.75 |

**Stephenville**

| | Daily Average MVAR | Daily Max MVAR |
|---|---|---|
| June 10, 2006 | -2.58 | 1.50 |
| June 11, 2006 | -7.13 | 1.41 |
| June 12, 2006 | -6.17 | 1.41 |
| June 13, 2006 | -5.95 | -0.30 |
| June 14, 2006 | -5.71 | -0.30 |
| June 15, 2006 | -0.30 | -0.30 |
| June 16, 2006 | -5.73 | -0.30 |
| June 17, 2006 | -9.26 | 1.50 |
| June 18, 2006 | -0.30 | -0.30 |
| June 19, 2006 | -0.30 | -0.30 |
| June 20, 2006 | -0.30 | -0.30 |
| June 21, 2006 | -6.13 | -0.30 |
| June 22, 2006 | -0.30 | -0.30 |
| June 23, 2006 | -0.30 | -0.30 |
| June 24, 2006 | -0.30 | -0.30 |
| June 25, 2006 | -0.30 | -0.30 |
| June 26, 2006 | -0.30 | -0.30 |
| June 27, 2006 | -0.30 | -0.30 |
| June 28, 2006 | -0.30 | -0.30 |
| June 29, 2006 | -0.30 | -0.30 |
| June 30, 2006 | -0.30 | -0.30 |
| July 1, 2006 | -0.96 | -0.30 |
| July 2, 2006 | -0.30 | -0.30 |
| July 3, 2006 | -0.30 | -0.30 |
| July 4, 2006 | -3.07 | 0.15 |
| July 5, 2006 | -0.30 | -0.30 |
| July 6, 2006 | -0.30 | -0.30 |
| July 7, 2006 | -0.30 | -0.30 |
| July 8, 2006 | -0.30 | -0.30 |
| July 9, 2006 | -0.30 | -0.30 |
| July 10, 2006 | -0.54 | -0.30 |
| July 11, 2006 | -5.14 | 4.02 |
| July 12, 2006 | -0.30 | -0.30 |
| July 13, 2006 | -0.30 | -0.30 |
| July 14, 2006 | -1.82 | 1.23 |
| July 15, 2006 | -0.30 | -0.30 |
| July 16, 2006 | -0.30 | -0.30 |
| July 17, 2006 | -0.30 | -0.30 |
| July 18, 2006 | -0.34 | -0.30 |
| July 19, 2006 | -0.45 | -0.39 |
| July 20, 2006 | -0.45 | -0.39 |
| July 21, 2006 | -0.45 | -0.39 |
| July 22, 2006 | -10.53 | 1.23 |
| July 23, 2006 | -0.39 | -0.39 |
| July 24, 2006 | -0.39 | -0.39 |
| July 25, 2006 | -0.41 | -0.39 |
| July 26, 2006 | -0.39 | -0.39 |
| July 27, 2006 | -0.41 | -0.39 |
| July 28, 2006 | -0.39 | -0.39 |
| July 29, 2006 | -4.03 | 0.24 |
| July 30, 2006 | -4.84 | 0.15 |
| July 31, 2006 | -10.58 | -5.42 |
| August 1, 2006 | -9.24 | -1.07 |
| August 2, 2006 | -0.42 | -0.30 |
| August 3, 2006 | -4.82 | 2.49 |
| August 4, 2006 | -3.51 | 0.06 |
| August 5, 2006 | -0.30 | -0.30 |
| August 6, 2006 | -0.30 | -0.30 |
| August 7, 2006 | -0.30 | -0.30 |

| | | |
|---|---|---|
| August 8, 2006 | -0.62 | 11.46 |
| August 9, 2006 | -4.25 | 7.26 |
| August 10, 2006 | -0.83 | 13.20 |
| August 11, 2006 | -3.93 | 9.06 |
| August 12, 2006 | -1.29 | 0.96 |
| August 13, 2006 | -4.78 | 0.06 |
| August 14, 2006 | 2.63 | 12.48 |
| August 15, 2006 | 3.82 | 12.48 |
| August 16, 2006 | 3.06 | 11.85 |
| August 17, 2006 | 2.31 | 14.55 |
| August 18, 2006 | 2.16 | 13.92 |
| August 19, 2006 | 6.48 | 21.30 |
| August 20, 2006 | 6.53 | 14.73 |
| August 21, 2006 | -3.90 | 6.54 |
| August 22, 2006 | 6.18 | 18.51 |
| August 23, 2006 | 6.50 | 15.27 |
| August 24, 2006 | -0.35 | 13.38 |
| August 25, 2006 | 4.56 | 19.59 |
| August 26, 2006 | -4.56 | 15.45 |
| August 27, 2006 | 1.41 | 11.31 |
| August 28, 2006 | 0.40 | 8.97 |
| August 29, 2006 | 1.92 | 12.84 |
| August 30, 2006 | 5.15 | 14.10 |
| August 31, 2006 | 6.28 | 26.61 |
| September 1, 2006 | 3.87 | 17.52 |
| September 2, 2006 | 0.13 | 9.78 |
| September 3, 2006 | 1.45 | 13.29 |
| September 4, 2006 | 1.43 | 15.81 |
| September 5, 2006 | -5.63 | 18.87 |
| September 6, 2006 | -3.72 | 6.27 |
| September 7, 2006 | 5.79 | 14.82 |
| September 8, 2006 | 2.13 | 9.87 |
| September 9, 2006 | -1.35 | 9.60 |
| September 10, 2006 | -0.41 | 9.87 |
| September 11, 2006 | 5.27 | 17.25 |
| September 12, 2006 | -2.23 | 8.70 |
| September 13, 2006 | -0.99 | 10.14 |
| September 14, 2006 | 6.96 | 13.47 |
| September 15, 2006 | -4.48 | 13.65 |
| September 16, 2006 | -2.14 | 15.36 |
| September 17, 2006 | 4.54 | 23.28 |
| September 18, 2006 | -2.57 | 11.67 |
| September 19, 2006 | 0.38 | 10.95 |
| September 20, 2006 | 1.86 | 6.81 |
| September 21, 2006 | -1.11 | 12.21 |
| September 22, 2006 | 4.21 | 11.58 |
| September 23, 2006 | -3.47 | 5.10 |
| September 24, 2006 | 1.77 | 11.58 |
| September 25, 2006 | -1.29 | 12.48 |
| September 26, 2006 | -4.87 | 6.00 |
| September 27, 2006 | 5.11 | 10.50 |
| September 28, 2006 | 1.57 | 13.29 |
| September 29, 2006 | 1.43 | 8.34 |
| September 30, 2006 | -1.57 | 10.05 |
| October 1, 2006 | -1.93 | 13.74 |
| October 2, 2006 | 1.49 | 11.31 |
| October 3, 2006 | 0.06 | 0.06 |
| October 4, 2006 | 0.06 | 0.06 |
| October 5, 2006 | 0.06 | 0.06 |
| October 6, 2006 | 0.06 | 0.06 |
| October 7, 2006 | 0.06 | 0.06 |
| October 8, 2006 | 0.06 | 0.06 |
| October 9, 2006 | 0.06 | 0.06 |
| October 10, 2006 | 1.55 | 7.26 |
| October 11, 2006 | 0.08 | 0.15 |
| October 12, 2006 | 0.06 | 0.06 |

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|---|---|---|
| August 8, 2006 | -0.30 | -0.30 |
| August 9, 2006 | -0.54 | -0.30 |
| August 10, 2006 | -0.30 | -0.30 |
| August 11, 2006 | -0.30 | -0.30 |
| August 12, 2006 | -0.30 | -0.30 |
| August 13, 2006 | -0.30 | -0.30 |
| August 14, 2006 | -0.30 | -0.30 |
| August 15, 2006 | -0.30 | -0.30 |
| August 16, 2006 | -0.30 | -0.30 |
| August 17, 2006 | -0.30 | -0.30 |
| August 18, 2006 | -2.01 | 0.51 |
| August 19, 2006 | -0.30 | -0.30 |
| August 20, 2006 | -0.30 | -0.30 |
| August 21, 2006 | -0.30 | -0.30 |
| August 22, 2006 | -0.30 | -0.30 |
| August 23, 2006 | -0.30 | -0.30 |
| August 24, 2006 | -0.30 | -0.30 |
| August 25, 2006 | -6.20 | -0.30 |
| August 26, 2006 | -2.77 | 0.24 |
| August 27, 2006 | -7.83 | -0.30 |
| August 28, 2006 | -4.78 | -0.30 |
| August 29, 2006 | -0.30 | -0.30 |
| August 30, 2006 | -0.30 | -0.30 |
| August 31, 2006 | -3.75 | -0.30 |
| September 1, 2006 | -5.87 | -0.30 |
| September 2, 2006 | -0.30 | -0.30 |
| September 3, 2006 | -0.30 | -0.30 |
| September 4, 2006 | -16.17 | -0.30 |
| September 5, 2006 | -9.37 | 0.78 |
| September 6, 2006 | -2.53 | -0.30 |
| September 7, 2006 | -0.31 | -0.30 |
| September 8, 2006 | -0.30 | -0.30 |
| September 9, 2006 | -0.30 | -0.30 |
| September 10, 2006 | -0.30 | -0.30 |
| September 11, 2006 | -12.28 | -0.30 |
| September 12, 2006 | -0.30 | -0.30 |
| September 13, 2006 | -16.96 | -0.30 |
| September 14, 2006 | -4.39 | 1.32 |
| September 15, 2006 | -0.30 | -0.30 |
| September 16, 2006 | -0.30 | -0.30 |
| September 17, 2006 | -0.30 | -0.30 |
| September 18, 2006 | -0.30 | -0.30 |
| September 19, 2006 | -0.30 | -0.30 |
| September 20, 2006 | -0.30 | -0.30 |
| September 21, 2006 | -0.30 | -0.30 |
| September 22, 2006 | -0.30 | -0.30 |
| September 23, 2006 | -0.30 | -0.30 |
| September 24, 2006 | -0.30 | -0.30 |
| September 25, 2006 | -3.71 | 3.48 |
| September 26, 2006 | -0.30 | -0.30 |
| September 27, 2006 | -0.30 | -0.30 |
| September 28, 2006 | -0.30 | -0.30 |
| September 29, 2006 | -3.27 | 1.50 |
| September 30, 2006 | -0.30 | -0.30 |
| October 1, 2006 | -0.27 | -0.21 |
| October 2, 2006 | -6.82 | -0.26 |
| October 3, 2006 | -8.89 | -0.30 |
| October 4, 2006 | -5.11 | 5.46 |
| October 5, 2006 | -8.02 | 4.83 |
| October 6, 2006 | -6.31 | 1.14 |
| October 7, 2006 | -0.30 | -0.30 |
| October 8, 2006 | -5.26 | -0.30 |
| October 9, 2006 | -2.48 | 0.42 |
| October 10, 2006 | -3.95 | 0.60 |
| October 11, 2006 | -0.30 | -0.30 |
| October 12, 2006 | -0.30 | -0.30 |

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|---|---|---|
| October 13, 2006 | 0.06 | 0.06 |
| October 14, 2006 | 0.06 | 0.06 |
| October 15, 2006 | 0.06 | 0.06 |
| October 16, 2006 | -1.83 | 5.91 |
| October 17, 2006 | -1.61 | 2.67 |
| October 18, 2006 | -4.09 | 0.69 |
| October 19, 2006 | 0.20 | 14.19 |
| October 20, 2006 | 0.06 | 0.06 |
| October 21, 2006 | 0.06 | 0.06 |
| October 22, 2006 | 0.07 | 0.09 |
| October 23, 2006 | -0.16 | 6.54 |
| October 24, 2006 | 1.82 | 19.14 |
| October 25, 2006 | -3.96 | 8.61 |
| October 26, 2006 | 4.61 | 14.10 |
| October 27, 2006 | -2.49 | 10.50 |
| October 28, 2006 | -1.20 | 9.26 |
| October 29, 2006 | 0.24 | 10.59 |
| October 30, 2006 | 1.40 | 5.91 |
| October 31, 2006 | 0.06 | 0.06 |
| November 1, 2006 | 0.06 | 0.06 |
| November 2, 2006 | 0.06 | 0.06 |
| November 3, 2006 | 0.06 | 0.06 |
| November 4, 2006 | 0.06 | 0.06 |
| November 5, 2006 | 0.06 | 0.06 |
| November 6, 2006 | 0.06 | 0.15 |
| November 7, 2006 | 0.06 | 0.06 |
| November 8, 2006 | 0.06 | 0.06 |
| November 9, 2006 | 0.06 | 0.06 |
| November 10, 2006 | -0.04 | 14.28 |
| November 11, 2006 | -0.95 | 3.30 |
| November 12, 2006 | -2.35 | 9.51 |
| November 13, 2006 | 4.95 | 20.13 |
| November 14, 2006 | 0.79 | 13.65 |
| November 15, 2006 | -2.64 | 10.77 |
| November 16, 2006 | -3.84 | 6.09 |
| November 17, 2006 | 1.64 | 14.46 |
| November 18, 2006 | -1.86 | 0.06 |
| November 19, 2006 | 0.06 | 0.06 |
| November 20, 2006 | 1.21 | 12.48 |
| November 21, 2006 | 5.16 | 22.20 |
| November 22, 2006 | 12.34 | 22.29 |
| November 23, 2006 | 8.56 | 23.46 |
| November 24, 2006 | -1.67 | 10.32 |
| November 25, 2006 | -0.70 | 12.12 |
| November 26, 2006 | 0.49 | 11.94 |
| November 27, 2006 | 5.84 | 20.49 |
| November 28, 2006 | 6.14 | 22.20 |
| November 29, 2006 | 4.39 | 10.95 |
| November 30, 2006 | 7.13 | 22.74 |
| December 1, 2006 | 2.78 | 15.90 |
| December 2, 2006 | -3.01 | 17.79 |
| December 3, 2006 | 0.60 | 9.87 |
| December 4, 2006 | 7.29 | 23.91 |
| December 5, 2006 | 2.38 | 15.90 |
| December 6, 2006 | 2.74 | 24.09 |
| December 7, 2006 | 1.97 | 27.59 |
| December 8, 2006 | 0.06 | 0.06 |
| December 9, 2006 | 3.08 | 14.91 |
| December 10, 2006 | -0.01 | 0.15 |
| December 11, 2006 | 0.63 | 9.15 |
| December 12, 2006 | 1.44 | 15.99 |
| December 13, 2006 | 5.39 | 31.10 |
| December 14, 2006 | 7.67 | 22.02 |
| December 15, 2006 | -0.92 | 14.19 |
| December 16, 2006 | -1.46 | 15.09 |
| December 17, 2006 | 2.37 | 17.34 |

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|---|---|---|
| October 13, 2006 | -0.30 | -0.30 |
| October 14, 2006 | -0.31 | -0.30 |
| October 15, 2006 | -10.28 | -0.30 |
| October 16, 2006 | -7.01 | 29.03 |
| October 17, 2006 | 1.28 | 32.81 |
| October 18, 2006 | -2.19 | 24.90 |
| October 19, 2006 | 2.34 | 7.53 |
| October 20, 2006 | 2.34 | 35.87 |
| October 21, 2006 | -4.49 | -0.30 |
| October 22, 2006 | -0.30 | -0.30 |
| October 23, 2006 | -0.75 | -0.30 |
| October 24, 2006 | -11.25 | 1.95 |
| October 25, 2006 | -3.84 | 4.29 |
| October 26, 2006 | -6.85 | -0.30 |
| October 27, 2006 | -7.90 | 1.14 |
| October 28, 2006 | -16.82 | -0.30 |
| October 29, 2006 | -9.45 | -0.30 |
| October 30, 2006 | -12.12 | -3.44 |
| October 31, 2006 | -14.47 | -7.76 |
| November 1, 2006 | -7.03 | 4.74 |
| November 2, 2006 | -7.22 | 9.60 |
| November 3, 2006 | -10.54 | 2.22 |
| November 4, 2006 | -9.08 | -0.30 |
| November 5, 2006 | -4.88 | 0.15 |
| November 6, 2006 | -0.33 | -0.21 |
| November 7, 2006 | -3.00 | 8.25 |
| November 8, 2006 | -5.64 | 6.00 |
| November 9, 2006 | -5.50 | 9.33 |
| November 10, 2006 | -0.55 | -0.30 |
| November 11, 2006 | -5.86 | -0.30 |
| November 12, 2006 | -7.97 | -0.30 |
| November 13, 2006 | -9.69 | 1.86 |
| November 14, 2006 | -1.45 | -0.30 |
| November 15, 2006 | -8.86 | 7.08 |
| November 16, 2006 | -20.86 | -11.81 |
| November 17, 2006 | -20.95 | -18.29 |
| November 18, 2006 | -32.53 | 71.95 |
| November 19, 2006 | -19.80 | -17.48 |
| November 20, 2006 | -15.81 | -6.32 |
| November 21, 2006 | -20.59 | -17.84 |
| November 22, 2006 | -18.29 | -10.82 |
| November 23, 2006 | -16.74 | -12.98 |
| November 24, 2006 | -19.84 | -17.66 |
| November 25, 2006 | -17.10 | -5.06 |
| November 26, 2006 | -10.88 | 0.15 |
| November 27, 2006 | -17.90 | 0.51 |
| November 28, 2006 | -6.71 | 2.67 |
| November 29, 2006 | -14.76 | 1.23 |
| November 30, 2006 | -14.32 | 0.15 |
| December 1, 2006 | -15.06 | -0.93 |
| December 2, 2006 | -15.55 | -11.00 |
| December 3, 2006 | -16.54 | -11.72 |
| December 4, 2006 | -15.13 | -11.54 |
| December 5, 2006 | -17.50 | -2.37 |
| December 6, 2006 | -10.75 | 0.15 |
| December 7, 2006 | -13.00 | 0.15 |
| December 8, 2006 | -14.10 | 3.03 |
| December 9, 2006 | -8.35 | 3.57 |
| December 10, 2006 | -14.83 | -11.00 |
| December 11, 2006 | -15.80 | -12.08 |
| December 12, 2006 | -14.67 | -11.18 |
| December 13, 2006 | -11.37 | -4.88 |
| December 14, 2006 | -20.67 | -18.38 |
| December 15, 2006 | -18.67 | -13.88 |
| December 16, 2006 | -16.34 | -11.72 |
| December 17, 2006 | -18.70 | -15.50 |

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|---|---|---|
| December 18, 2006 | 7.12 | 18.69 |
| December 19, 2006 | 7.41 | 24.45 |
| December 20, 2006 | 4.26 | 16.35 |
| December 21, 2006 | 6.29 | 21.48 |
| December 22, 2006 | 3.07 | 13.47 |
| December 23, 2006 | 8.43 | 20.13 |
| December 24, 2006 | 4.05 | 14.10 |
| December 25, 2006 | 0.02 | 0.06 |
| December 26, 2006 | 2.11 | 12.93 |
| December 27, 2006 | 3.09 | 20.94 |
| December 28, 2006 | 9.99 | 26.52 |
| December 29, 2006 | 14.95 | 31.64 |
| December 30, 2006 | 13.98 | 29.48 |
| December 31, 2006 | 8.01 | 27.05 |
| January 1, 2007 | 7.01 | 19.68 |
| January 2, 2007 | 8.01 | 17.88 |
| January 3, 2007 | 9.77 | 27.59 |
| January 4, 2007 | 1.77 | 16.08 |
| January 5, 2007 | 1.95 | 15.54 |
| January 6, 2007 | 1.38 | 13.20 |
| January 7, 2007 | -1.88 | 4.56 |
| January 8, 2007 | -0.07 | 9.33 |
| January 9, 2007 | 3.00 | 20.76 |
| January 10, 2007 | 10.22 | 20.04 |
| January 11, 2007 | 11.77 | 22.20 |
| January 12, 2007 | 11.18 | 20.85 |
| January 13, 2007 | 2.36 | 6.90 |
| January 14, 2007 | 9.66 | 21.84 |
| January 15, 2007 | 9.04 | 26.79 |
| January 16, 2007 | 6.37 | 16.98 |
| January 17, 2007 | 10.95 | 24.99 |
| January 18, 2007 | 9.48 | 18.51 |
| January 19, 2007 | 2.91 | 16.17 |
| January 20, 2007 | 2.99 | 16.44 |
| January 21, 2007 | 1.20 | 10.77 |
| January 22, 2007 | 6.63 | 28.76 |
| January 23, 2007 | 4.71 | 19.50 |
| January 24, 2007 | 1.35 | 4.74 |
| January 25, 2007 | 0.93 | 6.09 |
| January 26, 2007 | 4.25 | 23.46 |
| January 27, 2007 | 10.09 | 24.72 |
| January 28, 2007 | 2.51 | 8.61 |
| January 29, 2007 | 6.73 | 28.22 |
| January 30, 2007 | 11.76 | 28.94 |
| January 31, 2007 | 5.28 | 21.30 |
| February 1, 2007 | 8.90 | 23.28 |
| February 2, 2007 | -0.89 | 1.77 |
| February 3, 2007 | -0.03 | 0.06 |
| February 4, 2007 | 3.72 | 20.31 |
| February 5, 2007 | 2.43 | 16.44 |
| February 6, 2007 | 3.97 | 19.86 |
| February 7, 2007 | 2.50 | 13.02 |
| February 8, 2007 | 4.27 | 15.63 |
| February 9, 2007 | 2.16 | 5.73 |
| February 10, 2007 | 4.03 | 13.92 |
| February 11, 2007 | 5.75 | 22.29 |
| February 12, 2007 | 4.08 | 17.79 |
| February 13, 2007 | 7.70 | 14.46 |
| February 14, 2007 | 10.13 | 17.79 |
| February 15, 2007 | 11.18 | 21.03 |
| February 16, 2007 | 1.37 | 5.55 |
| February 17, 2007 | 3.06 | 17.79 |
| February 18, 2007 | 4.86 | 20.04 |
| February 19, 2007 | 8.47 | 23.73 |
| February 20, 2007 | 6.36 | 17.70 |
| February 21, 2007 | 3.34 | 18.24 |

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|---|---|---|
| December 18, 2006 | -17.47 | -12.98 |
| December 19, 2006 | -17.29 | -13.34 |
| December 20, 2006 | -15.89 | -6.14 |
| December 21, 2006 | -14.16 | -10.28 |
| December 22, 2006 | -14.29 | -10.10 |
| December 23, 2006 | -8.79 | -1.83 |
| December 24, 2006 | -15.32 | -4.70 |
| December 25, 2006 | -20.41 | -17.12 |
| December 26, 2006 | -18.67 | -9.74 |
| December 27, 2006 | -15.39 | -6.50 |
| December 28, 2006 | -10.03 | 1.05 |
| December 29, 2006 | 0.16 | 4.65 |
| December 30, 2006 | -5.01 | 0.15 |
| December 31, 2006 | 0.15 | 0.15 |
| January 1, 2007 | 0.15 | 0.15 |
| January 2, 2007 | 0.15 | 0.15 |
| January 3, 2007 | -4.96 | 0.15 |
| January 4, 2007 | -2.29 | 0.51 |
| January 5, 2007 | 0.15 | 0.15 |
| January 6, 2007 | 0.15 | 0.15 |
| January 7, 2007 | -6.26 | 0.15 |
| January 8, 2007 | -7.16 | 0.15 |
| January 9, 2007 | -9.21 | 0.15 |
| January 10, 2007 | 0.15 | 0.15 |
| January 11, 2007 | -1.19 | 0.15 |
| January 12, 2007 | 0.15 | 0.15 |
| January 13, 2007 | 0.15 | 0.15 |
| January 14, 2007 | 0.15 | 0.15 |
| January 15, 2007 | 0.15 | 0.15 |
| January 16, 2007 | 0.10 | 0.15 |
| January 17, 2007 | 0.15 | 0.15 |
| January 18, 2007 | 0.15 | 0.15 |
| January 19, 2007 | 0.15 | 0.15 |
| January 20, 2007 | 0.15 | 0.15 |
| January 21, 2007 | 0.15 | 0.15 |
| January 22, 2007 | 0.15 | 0.15 |
| January 23, 2007 | 0.15 | 0.15 |
| January 24, 2007 | -0.11 | 4.65 |
| January 25, 2007 | 0.02 | 0.15 |
| January 26, 2007 | 0.07 | 0.15 |
| January 27, 2007 | 0.15 | 0.15 |
| January 28, 2007 | 0.15 | 0.15 |
| January 29, 2007 | 0.15 | 0.15 |
| January 30, 2007 | 0.15 | 0.15 |
| January 31, 2007 | 0.15 | 0.15 |
| February 1, 2007 | 0.15 | 0.15 |
| February 2, 2007 | 0.09 | 0.15 |
| February 3, 2007 | 0.15 | 0.15 |
| February 4, 2007 | 0.15 | 0.15 |
| February 5, 2007 | 0.15 | 0.15 |
| February 6, 2007 | 0.15 | 0.15 |
| February 7, 2007 | 0.15 | 0.15 |
| February 8, 2007 | 0.14 | 0.15 |
| February 9, 2007 | 0.15 | 0.15 |
| February 10, 2007 | -1.34 | 0.15 |
| February 11, 2007 | -3.13 | 0.15 |
| February 12, 2007 | -0.15 | 0.33 |
| February 13, 2007 | -4.91 | 0.87 |
| February 14, 2007 | -0.33 | 0.15 |
| February 15, 2007 | -2.96 | 0.15 |
| February 16, 2007 | 0.15 | 0.15 |
| February 17, 2007 | 0.15 | 0.15 |
| February 18, 2007 | 0.15 | 0.15 |
| February 19, 2007 | 0.15 | 0.15 |
| February 20, 2007 | 0.15 | 0.15 |
| February 21, 2007 | 0.15 | 0.15 |

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|---|---|---|
| February 22, 2007 | 1.09 | 11.58 |
| February 23, 2007 | 5.84 | 19.86 |
| February 24, 2007 | 4.62 | 18.42 |
| February 25, 2007 | -1.71 | 4.74 |
| February 26, 2007 | -1.97 | 8.43 |
| February 27, 2007 | 3.26 | 19.05 |
| February 28, 2007 | 3.94 | 22.20 |
| March 1, 2007 | 7.81 | 26.97 |
| March 2, 2007 | 4.01 | 17.43 |
| March 3, 2007 | 5.32 | 20.04 |
| March 4, 2007 | 0.06 | 0.06 |
| March 5, 2007 | 6.28 | 19.05 |
| March 6, 2007 | -0.86 | 12.93 |
| March 7, 2007 | 14.53 | 29.39 |
| March 8, 2007 | 9.00 | 28.04 |
| March 9, 2007 | 14.33 | 27.59 |
| March 10, 2007 | 2.17 | 9.69 |
| March 11, 2007 | -0.04 | 0.06 |
| March 12, 2007 | 4.99 | 21.57 |
| March 13, 2007 | 0.52 | 6.63 |
| March 14, 2007 | -0.09 | 1.32 |
| March 15, 2007 | 0.06 | 0.06 |
| March 16, 2007 | 0.06 | 0.06 |
| March 17, 2007 | 3.01 | 21.39 |
| March 18, 2007 | 0.06 | 0.06 |
| March 19, 2007 | 0.06 | 0.06 |
| March 20, 2007 | 0.62 | 10.68 |
| March 21, 2007 | 1.56 | 12.84 |
| March 22, 2007 | 6.17 | 26.52 |
| March 23, 2007 | 1.05 | 11.49 |
| March 24, 2007 | 0.14 | 2.49 |
| March 25, 2007 | 0.90 | 10.23 |
| March 26, 2007 | 7.71 | 15.00 |
| March 27, 2007 | 1.33 | 4.74 |
| March 28, 2007 | 1.85 | 14.28 |
| March 29, 2007 | 0.90 | 10.59 |
| March 30, 2007 | 0.06 | 0.06 |
| March 31, 2007 | 0.06 | 0.06 |
| April 1, 2007 | 3.92 | 20.67 |
| April 2, 2007 | 1.97 | 23.46 |
| April 3, 2007 | 1.19 | 5.37 |
| April 4, 2007 | 4.44 | 10.68 |
| April 5, 2007 | 0.06 | 0.06 |
| April 6, 2007 | 0.06 | 0.06 |
| April 7, 2007 | 0.06 | 0.06 |
| April 8, 2007 | 0.06 | 0.06 |
| April 9, 2007 | 0.06 | 0.06 |
| April 10, 2007 | 1.84 | 8.88 |
| April 11, 2007 | 0.06 | 1.23 |
| April 12, 2007 | -0.95 | 6.36 |
| April 13, 2007 | 0.06 | 0.06 |
| April 14, 2007 | 3.57 | 21.57 |
| April 15, 2007 | 0.77 | 9.87 |
| April 16, 2007 | 2.98 | 16.17 |
| April 17, 2007 | 3.30 | 23.10 |
| April 18, 2007 | 0.82 | 4.20 |
| April 19, 2007 | 7.85 | 15.81 |
| April 20, 2007 | 2.01 | 16.71 |
| April 21, 2007 | 0.06 | 0.06 |
| April 22, 2007 | 0.06 | 0.06 |
| April 23, 2007 | 0.26 | 4.56 |
| April 24, 2007 | 0.06 | 0.06 |
| April 25, 2007 | 0.06 | 0.06 |
| April 26, 2007 | 0.06 | 0.06 |
| April 27, 2007 | 1.21 | 17.25 |
| April 28, 2007 | 4.79 | 17.97 |

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|---|---|---|
| February 22, 2007 | 0.15 | 0.15 |
| February 23, 2007 | 0.15 | 0.15 |
| February 24, 2007 | 0.15 | 0.15 |
| February 25, 2007 | 0.15 | 0.15 |
| February 26, 2007 | 0.15 | 0.15 |
| February 27, 2007 | 0.15 | 0.15 |
| February 28, 2007 | 0.15 | 0.15 |
| March 1, 2007 | 0.15 | 0.15 |
| March 2, 2007 | 0.15 | 0.15 |
| March 3, 2007 | 0.15 | 0.15 |
| March 4, 2007 | 0.15 | 0.15 |
| March 5, 2007 | -0.04 | 0.15 |
| March 6, 2007 | 0.20 | 1.41 |
| March 7, 2007 | 0.15 | 0.15 |
| March 8, 2007 | -0.12 | 0.15 |
| March 9, 2007 | 0.18 | 1.77 |
| March 10, 2007 | 0.15 | 0.15 |
| March 11, 2007 | 0.15 | 0.15 |
| March 12, 2007 | 0.15 | 0.15 |
| March 13, 2007 | -0.76 | 0.51 |
| March 14, 2007 | 0.12 | 0.16 |
| March 15, 2007 | 0.15 | 0.15 |
| March 16, 2007 | 0.15 | 0.15 |
| March 17, 2007 | 1.16 | 8.43 |
| March 18, 2007 | 0.15 | 0.15 |
| March 19, 2007 | 0.15 | 0.15 |
| March 20, 2007 | 0.15 | 0.15 |
| March 21, 2007 | 0.15 | 0.15 |
| March 22, 2007 | 0.15 | 0.15 |
| March 23, 2007 | -0.76 | 0.15 |
| March 24, 2007 | -6.32 | 0.15 |
| March 25, 2007 | -4.14 | 1.95 |
| March 26, 2007 | -4.87 | 2.67 |
| March 27, 2007 | 0.15 | 0.15 |
| March 28, 2007 | -3.98 | 0.15 |
| March 29, 2007 | -1.18 | 0.15 |
| March 30, 2007 | 0.15 | 0.15 |
| March 31, 2007 | 0.15 | 0.15 |
| April 1, 2007 | 0.15 | 0.15 |
| April 2, 2007 | -0.09 | 0.15 |
| April 3, 2007 | 0.14 | 0.15 |
| April 4, 2007 | -0.16 | 1.59 |
| April 5, 2007 | 0.15 | 0.15 |
| April 6, 2007 | 0.09 | 0.15 |
| April 7, 2007 | -1.28 | 1.23 |
| April 8, 2007 | 0.15 | 0.15 |
| April 9, 2007 | 0.18 | 3.39 |
| April 10, 2007 | -0.77 | 1.59 |
| April 11, 2007 | -2.50 | 0.15 |
| April 12, 2007 | -7.66 | 0.15 |
| April 13, 2007 | -0.34 | 0.15 |
| April 14, 2007 | 0.15 | 0.15 |
| April 15, 2007 | 0.15 | 0.15 |
| April 16, 2007 | 0.09 | 0.15 |
| April 17, 2007 | 0.21 | 0.51 |
| April 18, 2007 | 0.15 | 0.15 |
| April 19, 2007 | 0.09 | 0.15 |
| April 20, 2007 | -0.02 | 0.07 |
| April 21, 2007 | -4.26 | 0.15 |
| April 22, 2007 | -3.82 | 1.95 |
| April 23, 2007 | 0.15 | 0.15 |
| April 24, 2007 | 0.09 | 0.15 |
| April 25, 2007 | 0.11 | 0.15 |
| April 26, 2007 | 0.15 | 0.15 |
| April 27, 2007 | -0.45 | 0.15 |
| April 28, 2007 | -0.72 | 0.15 |

| | | |
|---|---|---|
| April 29, 2007 | 0.09 | 0.15 |
| April 30, 2007 | 0.06 | 0.06 |
| May 1, 2007 | 0.06 | 0.06 |
| May 2, 2007 | 0.06 | 0.06 |
| May 3, 2007 | 0.06 | 0.06 |
| May 4, 2007 | 0.06 | 0.06 |
| May 5, 2007 | 0.06 | 0.06 |
| May 6, 2007 | -0.06 | 0.06 |
| May 7, 2007 | 0.06 | 0.06 |
| May 8, 2007 | 0.06 | 0.06 |
| May 9, 2007 | 0.06 | 0.06 |
| May 10, 2007 | 0.06 | 0.06 |
| May 11, 2007 | 0.06 | 0.06 |
| May 12, 2007 | 0.06 | 0.06 |
| May 13, 2007 | 0.06 | 0.06 |
| May 14, 2007 | 0.06 | 0.06 |
| May 15, 2007 | 0.06 | 0.06 |
| May 16, 2007 | 0.06 | 0.06 |
| May 17, 2007 | 0.06 | 0.06 |
| May 18, 2007 | 0.06 | 0.06 |
| May 19, 2007 | 0.06 | 0.06 |
| May 20, 2007 | 0.06 | 0.06 |
| May 21, 2007 | 0.04 | 0.06 |
| May 22, 2007 | 0.05 | 0.06 |
| May 23, 2007 | 0.06 | 0.06 |
| May 24, 2007 | 0.06 | 0.06 |
| May 25, 2007 | 0.06 | 0.06 |
| May 26, 2007 | 0.06 | 0.06 |
| May 27, 2007 | 0.06 | 0.06 |
| May 28, 2007 | 0.06 | 0.06 |
| May 29, 2007 | 0.06 | 0.06 |
| May 30, 2007 | 0.06 | 0.06 |
| May 31, 2007 | -0.17 | 0.06 |
| June 1, 2007 | 0.05 | 0.06 |
| June 2, 2007 | 0.03 | 0.06 |
| June 3, 2007 | 0.06 | 0.06 |
| June 4, 2007 | 0.06 | 0.06 |
| June 5, 2007 | 0.06 | 0.06 |
| June 6, 2007 | 0.06 | 0.06 |
| June 7, 2007 | 0.04 | 0.06 |
| June 8, 2007 | 0.06 | 0.06 |
| June 9, 2007 | 0.06 | 0.06 |
| June 10, 2007 | 0.06 | 0.06 |
| June 11, 2007 | 1.43 | 15.09 |
| June 12, 2007 | 1.24 | 13.33 |
| June 13, 2007 | 0.06 | 0.06 |
| June 14, 2007 | 0.06 | 0.06 |
| June 15, 2007 | 0.06 | 0.06 |
| June 16, 2007 | 0.06 | 0.06 |
| June 17, 2007 | 0.05 | 0.06 |
| June 18, 2007 | 0.05 | 0.06 |
| June 19, 2007 | -0.07 | 16.71 |
| June 20, 2007 | -0.02 | 0.06 |
| June 21, 2007 | 0.06 | 0.06 |
| June 22, 2007 | 0.03 | 0.06 |
| June 23, 2007 | 3.12 | 7.98 |
| June 24, 2007 | 1.72 | 12.93 |
| June 25, 2007 | 0.06 | 0.06 |
| June 26, 2007 | 0.06 | 0.06 |
| June 27, 2007 | 0.06 | 0.06 |
| June 28, 2007 | 1.01 | 6.90 |
| June 29, 2007 | -1.13 | 2.58 |
| June 30, 2007 | -0.31 | 7.62 |
| July 1, 2007 | -4.21 | 2.04 |
| July 2, 2007 | 1.92 | 18.78 |
| July 3, 2007 | 7.36 | 14.28 |

| | | |
|---|---|---|
| April 29, 2007 | -5.72 | 1.41 |
| April 30, 2007 | -7.56 | 0.15 |
| May 1, 2007 | -8.34 | 0.15 |
| May 2, 2007 | -3.89 | 0.15 |
| May 3, 2007 | -3.04 | 0.15 |
| May 4, 2007 | -2.71 | 0.15 |
| May 5, 2007 | 0.15 | 0.15 |
| May 6, 2007 | -5.00 | 0.33 |
| May 7, 2007 | 0.15 | 0.15 |
| May 8, 2007 | -2.84 | 0.15 |
| May 9, 2007 | -3.70 | 0.15 |
| May 10, 2007 | -5.24 | 0.15 |
| May 11, 2007 | -5.40 | 0.15 |
| May 12, 2007 | -6.62 | 1.77 |
| May 13, 2007 | -12.11 | 0.51 |
| May 14, 2007 | -9.22 | -1.29 |
| May 15, 2007 | -14.38 | -0.21 |
| May 16, 2007 | 0.12 | 0.15 |
| May 17, 2007 | 0.15 | 0.15 |
| May 18, 2007 | 0.04 | 0.15 |
| May 19, 2007 | -5.40 | 1.77 |
| May 20, 2007 | -7.72 | 0.13 |
| May 21, 2007 | -5.79 | 0.15 |
| May 22, 2007 | -4.17 | 0.15 |
| May 23, 2007 | 0.15 | 0.15 |
| May 24, 2007 | -5.37 | 0.15 |
| May 25, 2007 | -7.39 | 0.15 |
| May 26, 2007 | -9.28 | 0.15 |
| May 27, 2007 | -9.90 | 0.15 |
| May 28, 2007 | -6.19 | 0.15 |
| May 29, 2007 | -5.65 | 0.15 |
| May 30, 2007 | 0.15 | 0.15 |
| May 31, 2007 | -1.85 | 0.15 |
| June 1, 2007 | -3.70 | 0.15 |
| June 2, 2007 | -7.32 | 0.51 |
| June 3, 2007 | 0.15 | 0.15 |
| June 4, 2007 | -3.55 | 0.15 |
| June 5, 2007 | -2.71 | 0.15 |
| June 6, 2007 | -14.80 | 0.15 |
| June 7, 2007 | -13.68 | -9.20 |
| June 8, 2007 | -7.95 | 1.59 |
| June 9, 2007 | -8.19 | 2.31 |
| June 10, 2007 | -12.59 | -5.24 |
| June 11, 2007 | -10.79 | 3.03 |
| June 12, 2007 | -9.53 | -2.37 |
| June 13, 2007 | -7.56 | 0.15 |
| June 14, 2007 | -3.84 | 0.15 |
| June 15, 2007 | -10.89 | 1.77 |
| June 16, 2007 | -17.54 | -15.32 |
| June 17, 2007 | -16.04 | -11.90 |
| June 18, 2007 | -8.77 | 0.15 |
| June 19, 2007 | -18.41 | -15.32 |
| June 20, 2007 | -11.68 | -4.88 |
| June 21, 2007 | -12.22 | -8.30 |
| June 22, 2007 | -10.62 | -5.78 |
| June 23, 2007 | -13.22 | -10.82 |
| June 24, 2007 | -11.35 | -8.12 |
| June 25, 2007 | -14.46 | -5.96 |
| June 26, 2007 | -10.37 | 0.51 |
| June 27, 2007 | -18.84 | -15.68 |
| June 28, 2007 | -17.26 | -14.60 |
| June 29, 2007 | -12.52 | 0.15 |
| June 30, 2007 | -16.25 | -13.35 |
| July 1, 2007 | -17.12 | -10.64 |
| July 2, 2007 | -15.85 | -11.00 |
| July 3, 2007 | -11.11 | -6.86 |

| | | |
|---|---|---|
| July 4, 2007 | 4.49 | 13.38 |
| July 5, 2007 | -0.09 | 10.41 |
| July 6, 2007 | -0.91 | 17.25 |
| July 7, 2007 | -2.33 | 3.93 |
| July 8, 2007 | -4.74 | 3.39 |
| July 9, 2007 | -1.22 | 5.55 |
| July 10, 2007 | 3.24 | 14.64 |
| July 11, 2007 | -1.67 | 1.77 |
| July 12, 2007 | -1.53 | 7.62 |
| July 13, 2007 | -3.57 | 6.18 |
| July 14, 2007 | -6.33 | 3.12 |
| July 15, 2007 | -2.66 | 6.90 |
| July 16, 2007 | -0.95 | 12.03 |
| July 17, 2007 | 2.38 | 11.67 |
| July 18, 2007 | 3.36 | 8.52 |
| July 19, 2007 | 2.26 | 8.97 |
| July 20, 2007 | -0.32 | 0.06 |
| July 21, 2007 | -1.15 | 5.28 |
| July 22, 2007 | 0.92 | 6.45 |
| July 23, 2007 | -0.93 | 6.54 |
| July 24, 2007 | 0.32 | 12.48 |
| July 25, 2007 | 1.96 | 10.05 |
| July 26, 2007 | 3.18 | 7.80 |
| July 27, 2007 | -2.78 | 1.77 |
| July 28, 2007 | -2.03 | 6.72 |
| July 29, 2007 | -0.40 | 14.73 |
| July 30, 2007 | 7.27 | 23.46 |
| July 31, 2007 | 3.66 | 19.68 |
| August 1, 2007 | -0.29 | 15.27 |
| August 2, 2007 | -2.61 | 13.74 |
| August 3, 2007 | -1.00 | 14.19 |
| August 4, 2007 | 0.97 | 18.33 |
| August 5, 2007 | 3.03 | 14.82 |
| August 6, 2007 | 5.60 | 18.96 |
| August 7, 2007 | 1.82 | 5.91 |
| August 8, 2007 | 2.67 | 14.10 |
| August 9, 2007 | 8.81 | 19.41 |
| August 10, 2007 | -2.13 | 4.65 |
| August 11, 2007 | 6.11 | 23.55 |
| August 12, 2007 | -2.11 | 6.81 |
| August 13, 2007 | -6.43 | 17.52 |
| August 14, 2007 | 0.94 | 12.21 |
| August 15, 2007 | 0.58 | 10.86 |
| August 16, 2007 | 0.09 | 11.04 |
| August 17, 2007 | 2.84 | 21.12 |
| August 18, 2007 | -7.73 | 9.15 |
| August 19, 2007 | -0.88 | 11.13 |
| August 20, 2007 | 2.46 | 16.17 |
| August 21, 2007 | -5.17 | 11.67 |
| August 22, 2007 | -3.26 | 10.23 |
| August 23, 2007 | -2.55 | 13.74 |
| August 24, 2007 | -1.80 | 7.35 |
| August 25, 2007 | -1.11 | 8.79 |
| August 26, 2007 | 0.61 | 11.31 |
| August 27, 2007 | 7.14 | 20.22 |
| August 28, 2007 | 7.73 | 23.55 |
| August 29, 2007 | 1.05 | 10.77 |
| August 30, 2007 | -3.19 | 14.73 |
| August 31, 2007 | 2.87 | 17.25 |
| September 1, 2007 | 1.51 | 13.02 |
| September 2, 2007 | 2.43 | 13.20 |
| September 3, 2007 | -6.39 | 4.06 |
| September 4, 2007 | -2.97 | 13.29 |
| September 5, 2007 | 1.63 | 20.22 |
| September 6, 2007 | -4.24 | 17.52 |
| September 7, 2007 | 0.70 | 12.82 |

| | | |
|---|---|---|
| July 4, 2007 | -17.35 | -15.14 |
| July 5, 2007 | -15.52 | -12.26 |
| July 6, 2007 | -16.05 | -11.54 |
| July 7, 2007 | -14.07 | -2.55 |
| July 8, 2007 | -9.70 | -3.26 |
| July 9, 2007 | -9.04 | -6.68 |
| July 10, 2007 | -11.91 | -5.60 |
| July 11, 2007 | -8.71 | 0.69 |
| July 12, 2007 | -18.78 | -14.42 |
| July 13, 2007 | -18.94 | -13.88 |
| July 14, 2007 | -18.71 | -16.40 |
| July 15, 2007 | -17.21 | -12.80 |
| July 16, 2007 | -12.28 | -3.80 |
| July 17, 2007 | -9.98 | 5.73 |
| July 18, 2007 | -17.02 | -8.66 |
| July 19, 2007 | -13.45 | -0.75 |
| July 20, 2007 | -13.69 | -7.40 |
| July 21, 2007 | -14.68 | -9.74 |
| July 22, 2007 | -19.14 | -15.14 |
| July 23, 2007 | -18.67 | -13.88 |
| July 24, 2007 | -17.09 | -12.98 |
| July 25, 2007 | -11.89 | 0.15 |
| July 26, 2007 | -17.23 | -12.80 |
| July 27, 2007 | -17.53 | -14.06 |
| July 28, 2007 | -18.43 | -15.86 |
| July 29, 2007 | -17.02 | -12.44 |
| July 30, 2007 | -16.56 | -13.70 |
| July 31, 2007 | -15.97 | -13.16 |
| August 1, 2007 | -15.66 | -11.18 |
| August 2, 2007 | -17.69 | -13.88 |
| August 3, 2007 | -17.29 | -14.78 |
| August 4, 2007 | -18.08 | -8.12 |
| August 5, 2007 | -19.51 | -10.82 |
| August 6, 2007 | -18.67 | -14.24 |
| August 7, 2007 | -15.70 | 0.15 |
| August 8, 2007 | -15.76 | -10.64 |
| August 9, 2007 | -18.45 | -14.06 |
| August 10, 2007 | -16.56 | 0.15 |
| August 11, 2007 | -15.40 | -10.82 |
| August 12, 2007 | -19.09 | -16.94 |
| August 13, 2007 | -18.29 | -15.32 |
| August 14, 2007 | -17.78 | -14.06 |
| August 15, 2007 | -19.36 | -15.86 |
| August 16, 2007 | -20.09 | -17.66 |
| August 17, 2007 | -20.09 | -17.30 |
| August 18, 2007 | -19.56 | -18.02 |
| August 19, 2007 | -20.04 | -18.92 |
| August 20, 2007 | -19.07 | -16.94 |
| August 21, 2007 | -19.41 | -17.48 |
| August 22, 2007 | -8.54 | 0.15 |
| August 23, 2007 | -7.86 | 1.41 |
| August 24, 2007 | -4.87 | 0.15 |
| August 25, 2007 | -10.00 | -8.66 |
| August 26, 2007 | -10.07 | -7.40 |
| August 27, 2007 | -6.68 | 0.15 |
| August 28, 2007 | -7.55 | 0.15 |
| August 29, 2007 | -3.30 | 0.15 |
| August 30, 2007 | 0.15 | 0.15 |
| August 31, 2007 | -2.38 | 0.15 |
| September 1, 2007 | -17.19 | -15.50 |
| September 2, 2007 | -17.16 | -16.22 |
| September 3, 2007 | -18.27 | -13.52 |
| September 4, 2007 | -17.55 | -13.52 |
| September 5, 2007 | -17.21 | -15.50 |
| September 6, 2007 | -16.35 | -13.88 |
| September 7, 2007 | -17.14 | -14.78 |

| | | |
|---|---|---|
| September 8, 2007 | -1.86 | 9.69 |
| September 9, 2007 | 5.06 | 12.75 |
| September 10, 2007 | 2.73 | 8.88 |
| September 11, 2007 | 1.90 | 14.01 |
| September 12, 2007 | -1.91 | 13.92 |
| September 13, 2007 | -0.54 | 2.94 |
| September 14, 2007 | 0.22 | 4.02 |
| September 15, 2007 | 10.10 | 18.78 |
| September 16, 2007 | -1.16 | 14.55 |
| September 17, 2007 | 3.13 | 10.23 |
| September 18, 2007 | 4.12 | 17.16 |
| September 19, 2007 | 1.43 | 12.12 |
| September 20, 2007 | 4.03 | 15.09 |
| September 21, 2007 | -0.11 | 11.22 |
| September 22, 2007 | -0.63 | 6.09 |
| September 23, 2007 | -2.52 | 11.04 |
| September 24, 2007 | -5.84 | 2.13 |
| September 25, 2007 | -2.87 | 8.34 |
| September 26, 2007 | 0.01 | 8.07 |
| September 27, 2007 | 3.87 | 12.03 |
| September 28, 2007 | 1.43 | 13.20 |
| September 29, 2007 | -4.31 | 6.90 |
| September 30, 2007 | -1.35 | 9.69 |
| October 1, 2007 | 2.21 | 14.55 |
| October 2, 2007 | -0.21 | 8.20 |
| October 3, 2007 | -5.72 | 3.21 |
| October 4, 2007 | -0.31 | 10.59 |
| October 5, 2007 | 4.38 | 7.80 |
| October 6, 2007 | 4.45 | 18.60 |
| October 7, 2007 | 6.71 | 12.39 |
| October 8, 2007 | 1.52 | 11.22 |
| October 9, 2007 | 5.54 | 13.29 |
| October 10, 2007 | 2.08 | 16.98 |
| October 11, 2007 | -1.11 | 4.75 |
| October 12, 2007 | -0.12 | 3.66 |
| October 13, 2007 | 4.18 | 9.96 |
| October 14, 2007 | -1.06 | 6.90 |
| October 15, 2007 | 0.13 | 0.51 |
| October 16, 2007 | 0.06 | 0.06 |
| October 17, 2007 | 0.06 | 0.06 |
| October 18, 2007 | -2.51 | 14.55 |
| October 19, 2007 | -2.24 | 11.49 |
| October 20, 2007 | 1.41 | 13.47 |
| October 21, 2007 | -1.67 | 12.57 |
| October 22, 2007 | -4.34 | 2.76 |
| October 23, 2007 | -4.73 | 0.87 |
| October 24, 2007 | 2.86 | 7.98 |
| October 25, 2007 | 1.39 | 6.90 |
| October 26, 2007 | -0.22 | 4.20 |
| October 27, 2007 | 0.82 | 9.33 |
| October 28, 2007 | 0.45 | 9.42 |
| October 29, 2007 | 0.19 | 8.25 |
| October 30, 2007 | 3.20 | 7.71 |
| October 31, 2007 | 2.20 | 9.24 |
| November 1, 2007 | 3.32 | 11.31 |

| | | |
|---|---|---|
| September 8, 2007 | -14.13 | -10.46 |
| September 9, 2007 | -14.26 | -12.44 |
| September 10, 2007 | -15.05 | -8.48 |
| September 11, 2007 | -12.61 | -7.94 |
| September 12, 2007 | -14.91 | -11.90 |
| September 13, 2007 | -13.52 | -10.46 |
| September 14, 2007 | -12.87 | -8.66 |
| September 15, 2007 | -14.31 | -12.26 |
| September 16, 2007 | -13.34 | -11.00 |
| September 17, 2007 | -12.74 | -10.64 |
| September 18, 2007 | -15.05 | -13.23 |
| September 19, 2007 | -16.03 | -13.70 |
| September 20, 2007 | -19.94 | -17.66 |
| September 21, 2007 | -20.39 | -19.28 |
| September 22, 2007 | -19.91 | -18.74 |
| September 23, 2007 | -20.21 | -18.38 |
| September 24, 2007 | -19.98 | -18.02 |
| September 25, 2007 | -14.85 | 8.43 |
| September 26, 2007 | -15.06 | 0.15 |
| September 27, 2007 | -13.48 | -11.36 |
| September 28, 2007 | -14.62 | -9.92 |
| September 29, 2007 | -16.45 | -12.80 |
| September 30, 2007 | -16.04 | -14.60 |
| October 1, 2007 | -16.11 | -14.06 |
| October 2, 2007 | -16.30 | -12.80 |
| October 3, 2007 | -17.58 | -15.68 |
| October 4, 2007 | -20.60 | -18.02 |
| October 5, 2007 | -20.54 | -20.39 |
| October 6, 2007 | -20.49 | -19.64 |
| October 7, 2007 | -20.65 | -15.50 |
| October 8, 2007 | -20.46 | -19.64 |
| October 9, 2007 | -20.73 | -19.46 |
| October 10, 2007 | -20.77 | -20.00 |
| October 11, 2007 | -20.62 | -18.38 |
| October 12, 2007 | -20.51 | -19.82 |
| October 13, 2007 | -20.91 | -20.18 |
| October 14, 2007 | -20.57 | -19.46 |
| October 15, 2007 | -20.40 | -19.64 |
| October 16, 2007 | -8.72 | 1.41 |
| October 17, 2007 | -10.52 | -6.50 |
| October 18, 2007 | -6.03 | 7.35 |
| October 19, 2007 | -16.65 | -13.52 |
| October 20, 2007 | -13.54 | -10.82 |
| October 21, 2007 | -20.29 | -14.42 |
| October 22, 2007 | -20.58 | -17.30 |
| October 23, 2007 | -11.18 | 0.87 |
| October 24, 2007 | -16.60 | -13.52 |
| October 25, 2007 | -20.53 | -18.56 |
| October 26, 2007 | -20.65 | -18.20 |
| October 27, 2007 | -16.30 | -0.75 |
| October 28, 2007 | -2.78 | 2.31 |
| October 29, 2007 | -5.13 | 0.15 |
| October 30, 2007 | -5.55 | 3.57 |
| October 31, 2007 | 0.06 | 0.15 |
| November 1, 2007 | -2.52 | 7.89 |

# HYDRO Email No. 3

## Hearn, Bill G.

**From:** AndreaMacDonald@nlh.nl.ca
**Sent:** Wednesday, October 24, 2007 8:25 AM
**To:** Hearn, Bill G.
**Subject:** Fw: HWD and SVL GT O&M Cost 2002 to 2006
**Attachments:** HWD and SVL GT O & M Cost 2002 to 2006.xls

More information for the gas turbine project. Please see the attached e-mail and spreadsheet.

Andrea

Andrea MacDonald, P. Eng.
Engineering Services - Mechanical
Newfoundland and Labrador Hydro
PO Box 12400
St. John's, NL A1B 4K7
www.nlh.nl.ca
Phone: 709-737-1205
Fax: 709-737-1900

----- Forwarded by Andrea MacDonald/NLHydro on 10/24/2007 08:53 AM -----

**Hughie Ireland/NLHydro**

10/24/2007 12:40 AM

To Andrea MacDonald/NLHydro@NLHydro
cc
Subject HWD and SVL GT O&M Cost 2002 to 2006

Andrea, I meant to send this sometime ago... Hope it is not too late .

Attached is a breakdown of the O&M cost for HWD and SVL gas Turbines. Please note this does not include fuel cost.

## HWD and SVLGT O&M Cost 2002 to 2006
## (Excluding Fuel Cost)

| Year | HWDGT | SVLGT |
|---|---|---|
| 2002 | $178,000 | $83,000 |
| 2003 | $236,000 | $105,000 |
| 2004 | $114,000 | $175,000 |
| 2005 | $425,000 | $114,000 |
| 2006 | $486,000 | $355,000 |
| 2007 (Forecast) | $300,000 | $160,000 |
| | | |
| **5 Yr Ave (Excluding 2007)** | **$287,800** | **$166,400** |

# HYDRO Email No. 4

## Hearn, Bill G.

**From:** AndreaMacDonald@nlh.nl.ca
**Sent:** Thursday, October 11, 2007 10:41 AM
**To:** Hearn, Bill G.
**Subject:** Fuel Prices - Stephenville and Hardwoods
**Attachments:** Fuel Prices - Hardwoods and Stephenville - Oct 10 2007.xls

Hi Bill,
Please see the attached file for the fuel prices for Stephenville and Hardwoods gas turbine facilities. This completes # 6 (item 4 - Annual Projected Fuel Costs Going Forward) of the Aug 21, 2007 minutes.
If you have any questions please let me know.
Thanks.
Andrea

Andrea MacDonald, P. Eng.
Engineering Services - Mechanical
Newfoundland and Labrador Hydro
PO Box 12400
St. John's, NL A1B 4K7
www.nlh.nl.ca
Phone: 709-737-1205
Fax: 709-737-1900

# #2 Gas Turbine Fuel Price Forecast for NLH Hardwoods and Stephenville Sites

(Nominal Dollars)

| | Hardwoods ($Cdn/l) | Stephenville ($Cdn/l) |
|---|---|---|
| ***2008*** | 0.624 | 0.686 |
| ***2009*** | 0.552 | 0.613 |
| ***2010*** | 0.557 | 0.619 |
| ***2011*** | 0.578 | 0.640 |
| ***2012*** | 0.606 | 0.668 |
| ***2013*** | 0.631 | 0.694 |
| ***2014*** | 0.666 | 0.730 |
| ***2015*** | 0.686 | 0.752 |
| ***2016*** | 0.721 | 0.788 |
| ***2017*** | 0.751 | 0.820 |
| ***2018*** | 0.786 | 0.856 |
| ***2019*** | 0.816 | 0.888 |
| ***2020*** | 0.847 | 0.919 |
| ***2021*** | 0.867 | 0.941 |
| ***2022*** | 0.882 | 0.957 |
| ***2023*** | 0.902 | 0.979 |
| ***2024*** | 0.922 | 1.001 |
| ***2025*** | 0.942 | 1.022 |
| ***2026*** | 0.957 | 1.039 |
| ***2027*** | 0.977 | 1.061 |
| ***2028*** | 1.002 | 1.088 |
| ***2029*** | 1.022 | 1.109 |
| ***2030*** | 1.042 | 1.131 |
| ***2031*** | 1.062 | 1.153 |
| ***2032*** | 1.087 | 1.180 |
| ***2033*** | 1.107 | 1.202 |
| ***2034*** | 1.132 | 1.229 |
| ***2035*** | 1.157 | 1.256 |
| ***2036*** | 1.177 | 1.278 |
| ***2037*** | 1.202 | 1.306 |

Note: 1. Gas Turbine prices reflect existing fuel supplier contract specifications and margins.
2. Pricing is consistent with NLH thermal fuel price forecast for Fall 2007.

Source: - PIRA Energy Group, Oil Price Forecast 10-04-07
- Market Analysis Section, System Planning Dept.

10-Oct-07
Market Analysis Section, System Planning Department

# HYDRO Email No. 5

## Hearn, Bill G.

**From:** AndreaMacDonald@nlh.nl.ca
**Sent:** Friday, October 26, 2007 8:39 AM
**To:** Hearn, Bill G.
**Subject:** Updated
**Attachments:** NLH Inflation & Escalation Forecast - Fall 2007.xls

Bill,
Please see the attached file for the newly updated 2007 escalation and inflation forecast details. I had previously sent you the 2006 version while I was waiting for this updated version.

Andrea

Andrea MacDonald, P. Eng.
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# TABLE 1
# NLH INFLATION AND ESCALATION FORECAST
# (1997 = 1.000)

| | General Inflation | | Electric Utility Construction Price Escalation | | | | | Operating & Maintenance (O&M) | |
|---|---|---|---|---|---|---|---|---|---|
| | GDP Implicit Price Deflator | Canadian CPI | Thermal Plant Construction | Hydraulic Plant Construction | Transmission Line Construction | Transformer Station Construction | Distribution Line Construction | More Material Less Labour | More Labor Less Material |
| **2000** | 1.055 | 1.055 | 1.058 | 1.069 | 1.081 | 1.076 | 1.091 | 1.057 | 1.059 |
| **2001** | 1.067 | 1.082 | 1.072 | 1.097 | 1.091 | 1.102 | 1.098 | 1.079 | 1.092 |
| **2002** | 1.078 | 1.106 | 1.102 | 1.116 | 1.107 | 1.123 | 1.106 | 1.098 | 1.121 |
| **2003** | 1.115 | 1.137 | 1.115 | 1.128 | 1.101 | 1.089 | 1.107 | 1.140 | 1.168 |
| **2004** | 1.148 | 1.158 | 1.180 | 1.177 | 1.141 | 1.101 | 1.111 | 1.174 | 1.204 |
| **2005** | 1.184 | 1.183 | 1.217 | 1.206 | 1.155 | 1.121 | 1.132 | 1.202 | 1.223 |
| **2006p** | 1.210 | 1.207 | 1.247 | 1.245 | 1.205 | 1.151 | 1.208 | 1.228 | 1.249 |
| **2007f** | 1.254 | 1.236 | 1.282 | 1.281 | 1.228 | 1.168 | 1.235 | 1.259 | 1.286 |
| **2008** | 1.285 | 1.267 | 1.320 | 1.319 | 1.259 | 1.191 | 1.266 | 1.290 | 1.325 |
| **2009** | 1.311 | 1.292 | 1.360 | 1.359 | 1.290 | 1.215 | 1.304 | 1.322 | 1.365 |
| **2010** | 1.337 | 1.318 | 1.401 | 1.400 | 1.322 | 1.239 | 1.343 | 1.355 | 1.406 |
| **2011** | 1.364 | 1.344 | 1.443 | 1.442 | 1.355 | 1.270 | 1.383 | 1.389 | 1.448 |
| **2012** | 1.391 | 1.371 | 1.486 | 1.485 | 1.389 | 1.302 | 1.424 | 1.424 | 1.491 |
| **2013** | 1.419 | 1.398 | 1.531 | 1.530 | 1.431 | 1.335 | 1.467 | 1.460 | 1.536 |
| **2014** | 1.447 | 1.426 | 1.577 | 1.576 | 1.474 | 1.368 | 1.511 | 1.497 | 1.582 |
| **2015** | 1.476 | 1.455 | 1.624 | 1.623 | 1.518 | 1.402 | 1.556 | 1.534 | 1.629 |
| **2016** | 1.506 | 1.484 | 1.673 | 1.672 | 1.564 | 1.437 | 1.603 | 1.572 | 1.678 |
| **2017** | 1.536 | 1.514 | 1.723 | 1.722 | 1.611 | 1.473 | 1.651 | 1.611 | 1.728 |
| **2018** | 1.567 | 1.544 | 1.775 | 1.774 | 1.659 | 1.510 | 1.701 | 1.651 | 1.780 |
| **2019** | 1.598 | 1.575 | 1.828 | 1.827 | 1.709 | 1.548 | 1.752 | 1.692 | 1.833 |
| **2020** | 1.630 | 1.607 | 1.883 | 1.882 | 1.760 | 1.587 | 1.805 | 1.734 | 1.888 |
| **2021** | 1.663 | 1.639 | 1.939 | 1.938 | 1.813 | 1.627 | 1.859 | 1.777 | 1.945 |
| **2022** | 1.696 | 1.672 | 1.997 | 1.996 | 1.867 | 1.668 | 1.915 | 1.821 | 2.003 |
| **2023** | 1.730 | 1.705 | 2.057 | 2.056 | 1.923 | 1.710 | 1.972 | 1.867 | 2.063 |
| **2024** | 1.765 | 1.739 | 2.119 | 2.118 | 1.981 | 1.753 | 2.031 | 1.914 | 2.125 |
| **2025** | 1.800 | 1.774 | 2.183 | 2.182 | 2.040 | 1.797 | 2.092 | 1.962 | 2.189 |
| **2026** | 1.836 | 1.809 | 2.248 | 2.247 | 2.101 | 1.842 | 2.155 | 2.011 | 2.255 |
| **2027** | 1.873 | 1.845 | 2.315 | 2.314 | 2.164 | 1.888 | 2.220 | 2.061 | 2.323 |

Notes:
1. p is preliminary Statistic's Canada data for Electric Utility Construction Price escalation.
2. General inflation post 2007 is a composite of inflation forecasts provided by Conference Board of Canada.
3. Project specific escalation for the Lower Churchill project is being developed by the LCP Division.

Data Sources: Statistics Canada
Conference Board of Canada

Oct-07
H:\Economic Analysis\Escalation\Fall 2007\[Draft Escalation Forecast for Fall 2007.xls]Indices
Market Analysis Section, System Planning Dept.

# HYDRO Email No. 6

## Hearn, Bill G.

**From:** NSeymour@nlh.nl.ca
**Sent:** Tuesday, November 13, 2007 12:16 PM
**To:** Hearn, Bill G.
**Cc:** AndreaMacDonald@nlh.nl.ca
**Subject:** Fw: NLH Gas Turbine Condition Assessment, fuel reports.

Bill,

Please see the annual fuel consumptions for each of the Hwds and Svl gas turbine sites. We only have reports for the past 4 years.

Nelson
----- Forwarded by Nelson Seymour/NLHydro on 11/13/2007 12:43 PM -----

Steve Carter/NLHydro
11/13/2007 08:55 AM

To: Nelson Seymour/NLHydro@NLHydro
cc: Andrea MacDonald/NLHydro@NLHydro, Hughie Ireland/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro
Subject: NLH Gas Turbine Condition Assessment, fuel reports.(Document link: Nelson Seymour)

Nelson,
I have the fuel reports for the last 4 years only.

2004...HWD...95288 litres, SVL...50241 litres.
2005...HWD...433380 litres, SVL...147566 litres.
2006...HWD...738552 litres, SVL...389686 litres.
2007...HWD...262691 litres, SVL...204485 litres.

Regards
Steve

Nelson Seymour/NLHydro
11/09/2007 01:42 PM

To: Steve Carter/NLHydro@NLHydro, James Wheeler/NLHydro@NLHydro
cc: Andrea MacDonald/NLHydro@NLHydro, Hughie Ireland/NLHydro@NLHydro
Subject: Fw: 21061 - NLH Gas Turbine Condition Assessment

Gentlemen,

Andrea is away until Wednesday. Can you forward this info. to myself next Tuesday please whereby I will relay to Bill Hearn? They are hoping to have a draft report ready for us next week.

Thks,
Nelson
----- Forwarded by Nelson Seymour/NLHydro on 11/09/2007 01:38 PM -----

| | | |
|---|---|---|
| "Hearn, Bill G." <Bill.Hearn@stantec.com> | | To |
| 11/09/2007 12:26 PM | <NSeymour@nlh.nl.ca>, <AndreaMacDonald@nlh.nl.ca> | cc |
| | "King, Brian" <Brian.King@stantec.com> | |
| | 21061 - NLH Gas Turbine Condition Assessment | Subject |

Andrea / Nelson:

Please provide asap, fuel consumption data at the Hardwoods and Stephenville sites on an annual basis for each of the past 5 years. We need this for our ongoing life cycle cost analysis work.

Thanks,
Bill

Bill Hearn, P. Eng
Senior Consultant - Power
Stantec (formerly Neill & Gunter)
#1 South 130 Eileen Stubbs Avenue
Dartmouth NS B3B 2C4
Ph: (902) 434-7331
Fx: (902) 462-1660
Bill.Hearn@stantec.com
stantec.com

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ü Please consider the environment before printing this email.

# APPENDIX 12
# FINANCIAL COST ANALYSIS MODEL RUNS

# Project Cost/Benefit Analysis Template

## Home Page

Current year
2007

| | |
|---|---|
| **Project Title** | Hardwoods/Stephenville GT's (Base Cases - Subcase 1) |
| **Project In-Service Year** | 2008 |
| **Number of Years in Study Analysis** | 16 |
| **Discount Rate** | 7.0% |
| **Present Worth Year** | 2007 |

**(costs are present worthed to January of that year)**

Print Home Page

REV 07.01

**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Hardwoods Refurb - Base Case 1A**
**HW Refurb - BC1A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,017,554 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 11,782,903 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,017,554 | - | - | 8,017,554 | 7,002,842 | 7,002,842 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 7,453,181 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 7,880,760 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 8,292,520 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 8,691,544 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 9,076,899 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 9,451,725 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 9,811,712 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 10,161,163 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 10,498,804 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 10,825,901 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 11,141,421 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 11,445,757 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 11,737,077 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 12,014,999 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 12,621,830 | - | - | 12,621,830 | 3,995,748 | 16,010,747 |
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Assumptions & Notes:

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| Date Revised | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Hardwoods Refurb - Base Case 1B**
**HW Refurb - BC1B**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 4,624,059 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 6,795,693 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 4,624,059 | - | - | 4,624,059 | 4,038,832 | 4,038,832 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 4,489,171 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 4,916,750 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 5,328,510 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 5,727,534 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 6,112,889 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 6,487,715 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 6,847,702 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 7,197,153 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 7,534,794 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 7,861,891 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 8,177,411 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 8,481,747 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 8,773,067 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 9,050,989 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 7,634,620 | - | - | 7,634,620 | 2,416,925 | 11,467,914 |
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Assumptions & Notes:

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| Date Revised | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Stephenville Refurb - Base Case 2A**
**SV ReFurb - BC2A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,050,389 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 11,831,159 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,050,389 | - | - | 8,050,389 | 7,031,522 | 7,031,522 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | - | 322,524 | - | - | 322,524 | 263,276 | 7,294,797 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 7,544,840 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | - | 337,120 | - | - | 337,120 | 240,362 | 7,785,202 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 8,017,614 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | - | 360,018 | - | - | 360,018 | 224,201 | 8,241,814 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 8,459,517 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | - | 384,417 | - | - | 384,417 | 209,097 | 8,668,614 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 8,871,278 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 9,066,996 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 9,256,341 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 9,438,910 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 9,614,723 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 9,783,046 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 9,943,602 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | - | 12,316,747 | - | - | 12,316,747 | 3,899,167 | 13,842,768 |
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Assumptions & Notes:

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| Date Revised | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Stephenville Refurb - Base Case 2B**
**SV ReFurb - BC2B**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 4,656,894 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 6,843,949 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 4,656,894 | - | - | 4,656,894 | 4,067,512 | 4,067,512 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | 51,765 | 374,289 | - | - | 374,289 | 305,531 | 4,373,043 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 4,623,086 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | 66,488 | 403,607 | - | - | 403,607 | 287,766 | 4,910,853 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 5,143,264 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | 93,138 | 453,156 | - | - | 453,156 | 282,203 | 5,425,467 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 5,643,169 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | 98,044 | 482,461 | - | - | 482,461 | 262,427 | 5,905,596 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 6,108,260 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 6,303,978 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 6,493,323 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 6,675,892 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 6,851,705 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 7,020,028 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 7,180,584 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | 150,491 | 7,480,028 | - | - | 7,480,028 | 2,367,985 | 9,548,569 |
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Assumptions & Notes:

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**

**DVAR - Hardwoods**

**DVAR**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 10,000,000 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | U |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 10,000,000 | - | - | 10,000,000 | 8,734,387 | 8,734,387 |
| 2 | 2009 | 27,479 | | - | - | 27,479 | - | - | 27,479 | 22,431 | 8,756,819 |
| 3 | 2010 | 28,304 | | - | - | 28,304 | - | - | 28,304 | 21,593 | 8,778,412 |
| 4 | 2011 | 29,153 | | - | - | 29,153 | - | - | 29,153 | 20,786 | 8,799,197 |
| 5 | 2012 | 30,028 | | - | - | 30,028 | - | - | 30,028 | 20,009 | 8,819,206 |
| 6 | 2013 | 30,928 | | - | - | 30,928 | - | - | 30,928 | 19,261 | 8,838,466 |
| 7 | 2014 | 31,856 | | - | - | 31,856 | - | - | 31,856 | 18,541 | 8,857,007 |
| 8 | 2015 | 32,812 | | - | - | 32,812 | - | - | 32,812 | 17,847 | 8,874,854 |
| 9 | 2016 | 33,796 | | - | - | 33,796 | - | - | 33,796 | 17,180 | 8,892,035 |
| 10 | 2017 | 34,810 | | - | - | 34,810 | - | - | 34,810 | 16,538 | 8,908,573 |
| 11 | 2018 | 35,854 | | - | - | 35,854 | - | - | 35,854 | 15,920 | 8,924,493 |
| 12 | 2019 | 36,930 | | - | - | 36,930 | - | - | 36,930 | 15,325 | 8,939,817 |
| 13 | 2020 | 38,038 | | - | - | 38,038 | - | - | 38,038 | 14,752 | 8,954,569 |
| 14 | 2021 | 39,179 | | - | - | 39,179 | - | - | 39,179 | 14,200 | 8,968,769 |
| 15 | 2022 | 40,354 | | - | - | 40,354 | - | - | 40,354 | 13,669 | 8,982,439 |
| 16 | 2023 | 41,565 | | - | - | 41,565 | - | - | 41,565 | 13,158 | 8,995,597 |
| | | | | | | - | | | - | - | - |
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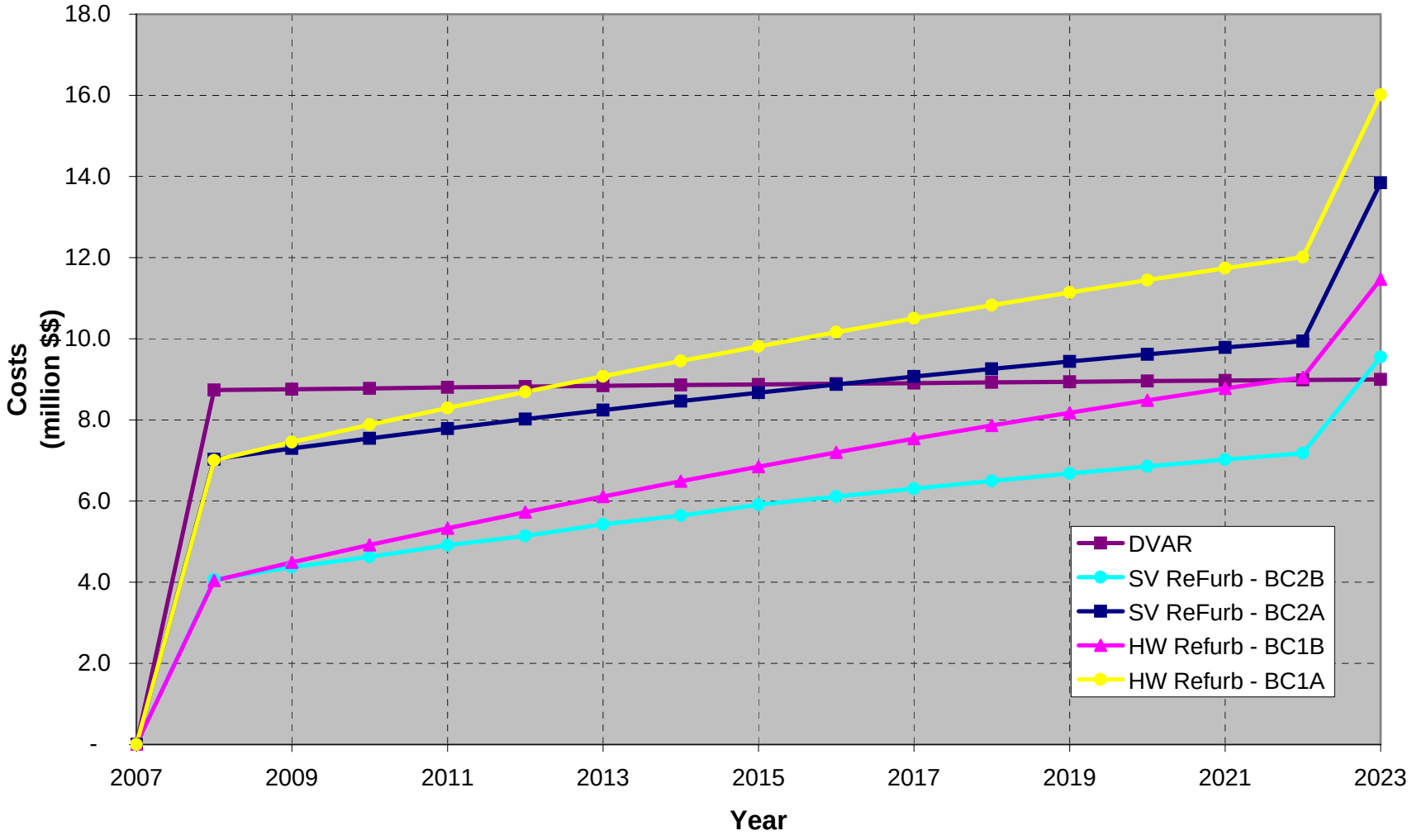
Assumptions & Notes:

Date Revised

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# Alternative Comparison
# Cumulative Net Present Value

For the options in which refurbishment is completed in 2008, it is assumed that refurbishment will again be required in 2023



# Hardwoods/Stephenville GT's (Base Cases - Subcase 1)

## Alternative Comparison

***Cumulative Net Present Value***
***To The Year***
**2023**

| Alternatives | Cumulative Net Present Value (CPW) | CPW Difference between Alternative and the Least Cost Alternative |
|---|---|---|
| Hardwoods Refurb - Base Case 1A | 16,010,747 | 7,015,150 |
| Hardwoods Refurb - Base Case 1B | 11,467,914 | 2,472,317 |
| Stephenville Refurb - Base Case 2A | 13,842,768 | 4,847,171 |
| Stephenville Refurb - Base Case 2B | 9,548,569 | 552,972 |
| DVAR - Hardwoods | 8,995,597 | 0 |

| | | |
|---|---|---|
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# Project Cost/Benefit Analysis Template

## Home Page

Current year
2007

| | |
|---|---|
| **Project Title** | Hardwoods/Stephenville GT's (Base Cases - Subcase 2) |
| **Project In-Service Year** | 2008 |
| **Number of Years in Study Analysis** | 16 |
| **Discount Rate** | 7.0% |
| **Present Worth Year** | 2007 |

**(costs are present worthed to January of that year)**

Print Home Page

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Hardwoods Refurb - Base Case 1A**
**HW Refurb - BC1A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,017,554 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,017,554 | - | - | 8,017,554 | 7,002,842 | 7,002,842 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 7,453,181 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 7,880,760 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 8,292,520 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 8,691,544 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 9,076,899 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 9,451,725 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 9,811,712 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 10,161,163 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 10,498,804 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 10,825,901 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 11,141,421 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 11,445,757 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 11,737,077 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 12,014,999 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 56,478,545 | - | - | 56,478,545 | 17,879,661 | 29,894,660 |
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Assumptions & Notes:

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Hardwoods Refurb - Base Case 1B**
**HW Refurb - BC1B**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 4,624,059 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 4,624,059 | - | - | 4,624,059 | 4,038,832 | 4,038,832 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 4,489,171 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 4,916,750 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 5,328,510 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 5,727,534 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 6,112,889 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 6,487,715 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 6,847,702 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 7,197,153 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 7,534,794 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 7,861,891 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 8,177,411 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 8,481,747 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 8,773,067 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 9,050,989 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 56,478,545 | - | - | 56,478,545 | 17,879,661 | 26,930,650 |
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Assumptions & Notes:

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Stephenville Refurb - Base Case 2A**
**SV ReFurb - BC2A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,050,389 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,050,389 | - | - | 8,050,389 | 7,031,522 | 7,031,522 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | - | 322,524 | - | - | 322,524 | 263,276 | 7,294,797 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 7,544,840 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | - | 337,120 | - | - | 337,120 | 240,362 | 7,785,202 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 8,017,614 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | - | 360,018 | - | - | 360,018 | 224,201 | 8,241,814 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 8,459,517 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | - | 384,417 | - | - | 384,417 | 209,097 | 8,668,614 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 8,871,278 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 9,066,996 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 9,256,341 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 9,438,910 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 9,614,723 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 9,783,046 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 9,943,602 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | - | 56,125,206 | - | - | 56,125,206 | 17,767,803 | 27,711,405 |
| | | | | | | - | | | - | - | - |
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Assumptions & Notes:

Date Revised
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**
**Stephenville Refurb - Base Case 2B**
**SV ReFurb - BC2B**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 4,656,894 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 4,656,894 | - | - | 4,656,894 | 4,067,512 | 4,067,512 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | 51,765 | 374,289 | - | - | 374,289 | 305,531 | 4,373,043 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 4,623,086 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | 66,488 | 403,607 | - | - | 403,607 | 287,766 | 4,910,853 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 5,143,264 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | 93,138 | 453,156 | - | - | 453,156 | 282,203 | 5,425,467 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 5,643,169 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | 98,044 | 482,461 | - | - | 482,461 | 262,427 | 5,905,596 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 6,108,260 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 6,303,978 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 6,493,323 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 6,675,892 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 6,851,705 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 7,020,028 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 7,180,584 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | 150,491 | 56,275,697 | - | - | 56,275,697 | 17,815,444 | 24,996,028 |
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Assumptions & Notes:

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Base Ca**

**DVAR - One Site**

**DVAR**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 10,000,000 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | U |

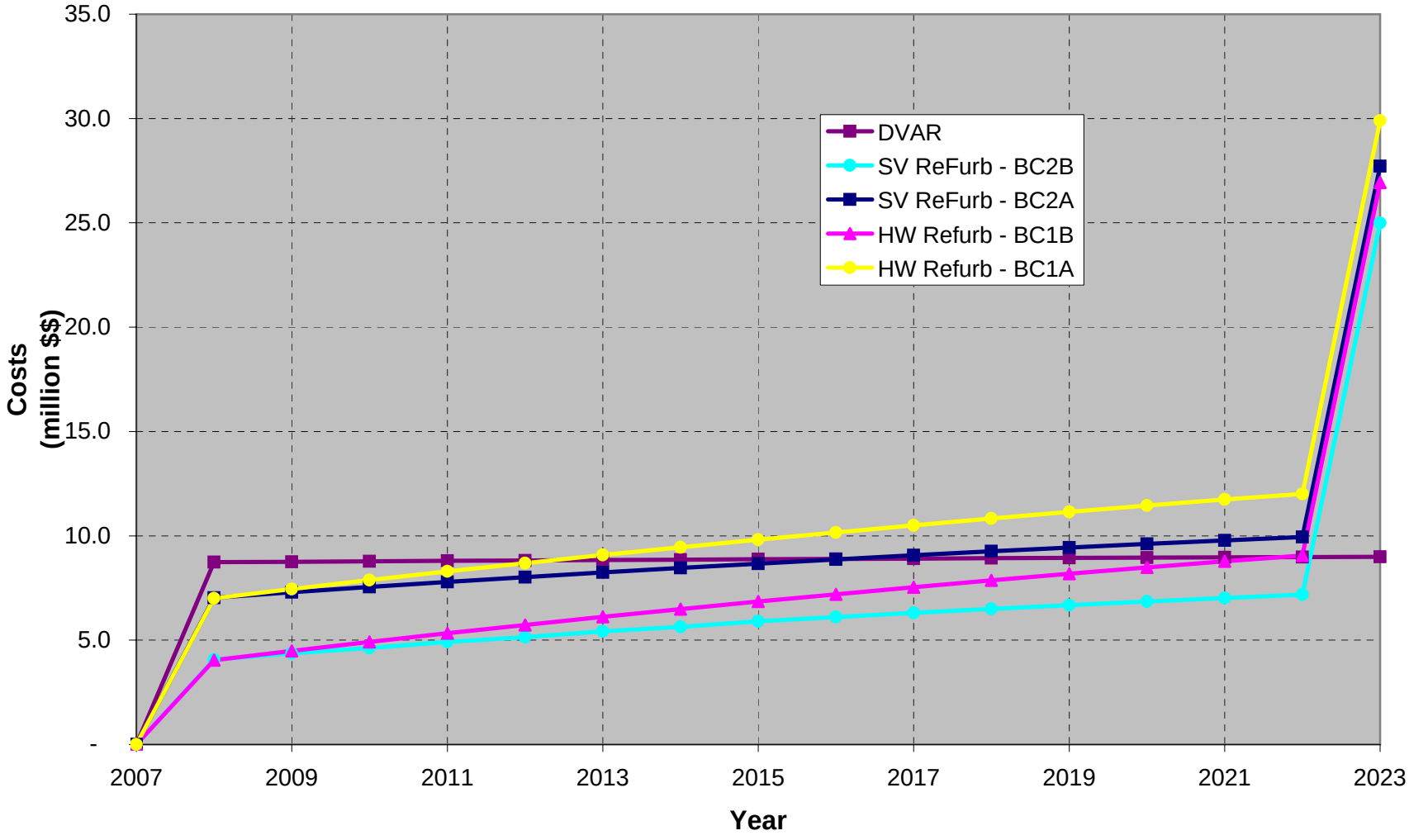
| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 10,000,000 | - | - | 10,000,000 | 8,734,387 | 8,734,387 |
| 2 | 2009 | 27,479 | | - | - | 27,479 | - | - | 27,479 | 22,431 | 8,756,819 |
| 3 | 2010 | 28,304 | | - | - | 28,304 | - | - | 28,304 | 21,593 | 8,778,412 |
| 4 | 2011 | 29,153 | | - | - | 29,153 | - | - | 29,153 | 20,786 | 8,799,197 |
| 5 | 2012 | 30,028 | | - | - | 30,028 | - | - | 30,028 | 20,009 | 8,819,206 |
| 6 | 2013 | 30,928 | | - | - | 30,928 | - | - | 30,928 | 19,261 | 8,838,466 |
| 7 | 2014 | 31,856 | | - | - | 31,856 | - | - | 31,856 | 18,541 | 8,857,007 |
| 8 | 2015 | 32,812 | | - | - | 32,812 | - | - | 32,812 | 17,847 | 8,874,854 |
| 9 | 2016 | 33,796 | | - | - | 33,796 | - | - | 33,796 | 17,180 | 8,892,035 |
| 10 | 2017 | 34,810 | | - | - | 34,810 | - | - | 34,810 | 16,538 | 8,908,573 |
| 11 | 2018 | 35,854 | | - | - | 35,854 | - | - | 35,854 | 15,920 | 8,924,493 |
| 12 | 2019 | 36,930 | | - | - | 36,930 | - | - | 36,930 | 15,325 | 8,939,817 |
| 13 | 2020 | 38,038 | | - | - | 38,038 | - | - | 38,038 | 14,752 | 8,954,569 |
| 14 | 2021 | 39,179 | | - | - | 39,179 | - | - | 39,179 | 14,200 | 8,968,769 |
| 15 | 2022 | 40,354 | | - | - | 40,354 | - | - | 40,354 | 13,669 | 8,982,439 |
| 16 | 2023 | 41,565 | | - | - | 41,565 | - | - | 41,565 | 13,158 | 8,995,597 |
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Assumptions & Notes:

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# Alternative Comparison
# Cumulative Net Present Value

For the options in which refurbishment is completed in 2008, it is assumed that replacement of the refurbished components will be required in 2023



# Hardwoods/Stephenville GT's (Base Cases - Subcase 2)

## Alternative Comparison

***Cumulative Net Present Value***
***To The Year***
**2023**

| Alternatives | Cumulative Net Present Value (CPW) | CPW Difference between Alternative and the Least Cost Alternative |
|---|---|---|
| Hardwoods Refurb - Base Case 1A | 29,894,660 | 20,899,063 |
| Hardwoods Refurb - Base Case 1B | 26,930,650 | 17,935,053 |
| Stephenville Refurb - Base Case 2A | 27,711,405 | 18,715,807 |
| Stephenville Refurb - Base Case 2B | 24,996,028 | 16,000,431 |
| DVAR - One Site | 8,995,597 | 0 |

| | | |
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| Date Revised: | | |

# Project Cost/Benefit Analysis Template

## Home Page

Current year
2007

| | |
|---|---|
| **Project Title** | Hardwoods/Stephenville GT's (Options Subcase 1) |
| **Project In-Service Year** | 2008 |
| **Number of Years in Study Analysis** | 16 |
| **Discount Rate** | 7.0% |
| **Present Worth Year** | 2007 |

**(costs are present worthed to January of that year)**

Print Home Page

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**Hardwoods Refurb - Base Case 1A**
**HW Refurb - BC1A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,017,554 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 11,782,903 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,017,554 | - | - | 8,017,554 | 7,002,842 | 7,002,842 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 7,453,181 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 7,880,760 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 8,292,520 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 8,691,544 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 9,076,899 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 9,451,725 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 9,811,712 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 10,161,163 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 10,498,804 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 10,825,901 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 11,141,421 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 11,445,757 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 11,737,077 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 12,014,999 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 12,621,830 | - | - | 12,621,830 | 3,995,748 | 16,010,747 |
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes refurbishment required in 2023 (reflected as replacement cost)

| | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**Stephenville Refurb - Base Case 2A**
**SV ReFurb - BC2A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,050,389 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 11,831,159 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,050,389 | - | - | 8,050,389 | 7,031,522 | 7,031,522 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | - | 322,524 | - | - | 322,524 | 263,276 | 7,294,797 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 7,544,840 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | - | 337,120 | - | - | 337,120 | 240,362 | 7,785,202 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 8,017,614 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | - | 360,018 | - | - | 360,018 | 224,201 | 8,241,814 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 8,459,517 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | - | 384,417 | - | - | 384,417 | 209,097 | 8,668,614 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 8,871,278 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 9,066,996 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 9,256,341 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 9,438,910 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 9,614,723 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 9,783,046 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 9,943,602 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | - | 12,316,747 | - | - | 12,316,747 | 3,899,167 | 13,842,768 |
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes refurbishment required in 2023 (reflected as replacement cost)

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**New GT/Refurb Alt - Option 1**
**New GT - Opt1**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 30,500,170 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 5,891,452 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 30,500,170 | - | - | 30,500,170 | 26,640,030 | 26,640,030 |
| 2 | 2009 | 226,335 | 0.55 | 252,074 | - | 478,409 | - | - | 478,409 | 390,525 | 27,030,554 |
| 3 | 2010 | 231,541 | 0.56 | 254,358 | - | 485,898 | - | - | 485,898 | 370,690 | 27,401,244 |
| 4 | 2011 | 236,866 | 0.58 | 263,947 | - | 500,814 | - | - | 500,814 | 357,073 | 27,758,317 |
| 5 | 2012 | 242,788 | 0.61 | 276,734 | - | 519,522 | - | - | 519,522 | 346,179 | 28,104,496 |
| 6 | 2013 | 248,858 | 0.63 | 288,150 | - | 537,008 | - | - | 537,008 | 334,421 | 28,438,918 |
| 7 | 2014 | 255,079 | 0.67 | 304,133 | - | 559,212 | - | - | 559,212 | 325,467 | 28,764,385 |
| 8 | 2015 | 261,456 | 0.69 | 313,266 | - | 574,722 | - | - | 574,722 | 312,611 | 29,076,995 |
| 9 | 2016 | 267,992 | 0.72 | 329,249 | - | 597,242 | - | - | 597,242 | 303,607 | 29,380,603 |
| 10 | 2017 | 274,692 | 0.75 | 342,949 | - | 617,641 | - | - | 617,641 | 293,437 | 29,674,040 |
| 11 | 2018 | 281,560 | 0.79 | 358,932 | - | 640,491 | - | - | 640,491 | 284,386 | 29,958,426 |
| 12 | 2019 | 288,599 | 0.82 | 372,632 | - | 661,230 | - | - | 661,230 | 274,387 | 30,232,813 |
| 13 | 2020 | 295,814 | 0.85 | 386,788 | - | 682,601 | - | - | 682,601 | 264,725 | 30,497,537 |
| 14 | 2021 | 303,209 | 0.87 | 395,921 | - | 699,130 | - | - | 699,130 | 253,397 | 30,750,934 |
| 15 | 2022 | 310,789 | 0.88 | 402,771 | - | 713,560 | - | - | 713,560 | 241,707 | 30,992,642 |
| 16 | 2023 | 318,559 | 0.90 | 410,991 | - | 6,621,001 | - | - | 6,621,001 | 2,096,039 | 33,088,681 |
| | | | | | | - | | | - | - | - |
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Assumptions & Notes:

-New engines, refurbishment of alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 75% of historical average
-Assumes partial refurbishment required in 2023 (reflected as replacement cost)

| | | |
|---|---|---|
| Date Revised | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**New Alt/Refurb GT - Option 2**
**New Alt - Opt2**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 10,743,124 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 5,891,452 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 10,743,124 | - | - | 10,743,124 | 9,383,461 | 9,383,461 |
| 2 | 2009 | 241,424 | 0.55 | 280,083 | - | 521,507 | - | - | 521,507 | 425,705 | 9,809,165 |
| 3 | 2010 | 246,977 | 0.56 | 282,620 | - | 529,596 | - | - | 529,596 | 404,027 | 10,213,192 |
| 4 | 2011 | 252,657 | 0.58 | 293,275 | - | 545,932 | - | - | 545,932 | 389,242 | 10,602,434 |
| 5 | 2012 | 258,974 | 0.61 | 307,482 | - | 566,456 | - | - | 566,456 | 377,453 | 10,979,888 |
| 6 | 2013 | 265,448 | 0.63 | 320,167 | - | 585,615 | - | - | 585,615 | 364,692 | 11,344,579 |
| 7 | 2014 | 272,084 | 0.67 | 337,926 | - | 610,010 | - | - | 610,010 | 355,031 | 11,699,611 |
| 8 | 2015 | 278,886 | 0.69 | 348,074 | - | 626,960 | - | - | 626,960 | 341,025 | 12,040,635 |
| 9 | 2016 | 285,859 | 0.72 | 365,833 | - | 651,691 | - | - | 651,691 | 331,287 | 12,371,922 |
| 10 | 2017 | 293,005 | 0.75 | 381,054 | - | 674,059 | - | - | 674,059 | 320,241 | 12,692,163 |
| 11 | 2018 | 300,330 | 0.79 | 398,813 | - | 699,143 | - | - | 699,143 | 310,428 | 13,002,591 |
| 12 | 2019 | 307,838 | 0.82 | 414,035 | - | 721,874 | - | - | 721,874 | 299,552 | 13,302,143 |
| 13 | 2020 | 315,534 | 0.85 | 429,764 | - | 745,299 | - | - | 745,299 | 289,040 | 13,591,183 |
| 14 | 2021 | 323,423 | 0.87 | 439,912 | - | 763,335 | - | - | 763,335 | 276,668 | 13,867,850 |
| 15 | 2022 | 331,508 | 0.88 | 447,523 | - | 779,032 | - | - | 779,032 | 263,885 | 14,131,735 |
| 16 | 2023 | 339,796 | 0.90 | 456,656 | - | 6,687,904 | - | - | 6,687,904 | 2,117,219 | 16,248,954 |
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Assumptions & Notes:

-New alternator, refurbishment of engines and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 80% of historical average
-Assumes partial refurbishment required in 2023 (reflected as replacement cost)

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**
**Hardwoods/Stephenville GT's (Options**
**New Unit Complete - Option 3**
**New Unit - Opt3**

***Note: Costs are shown as positive values;Benefits as negative values***

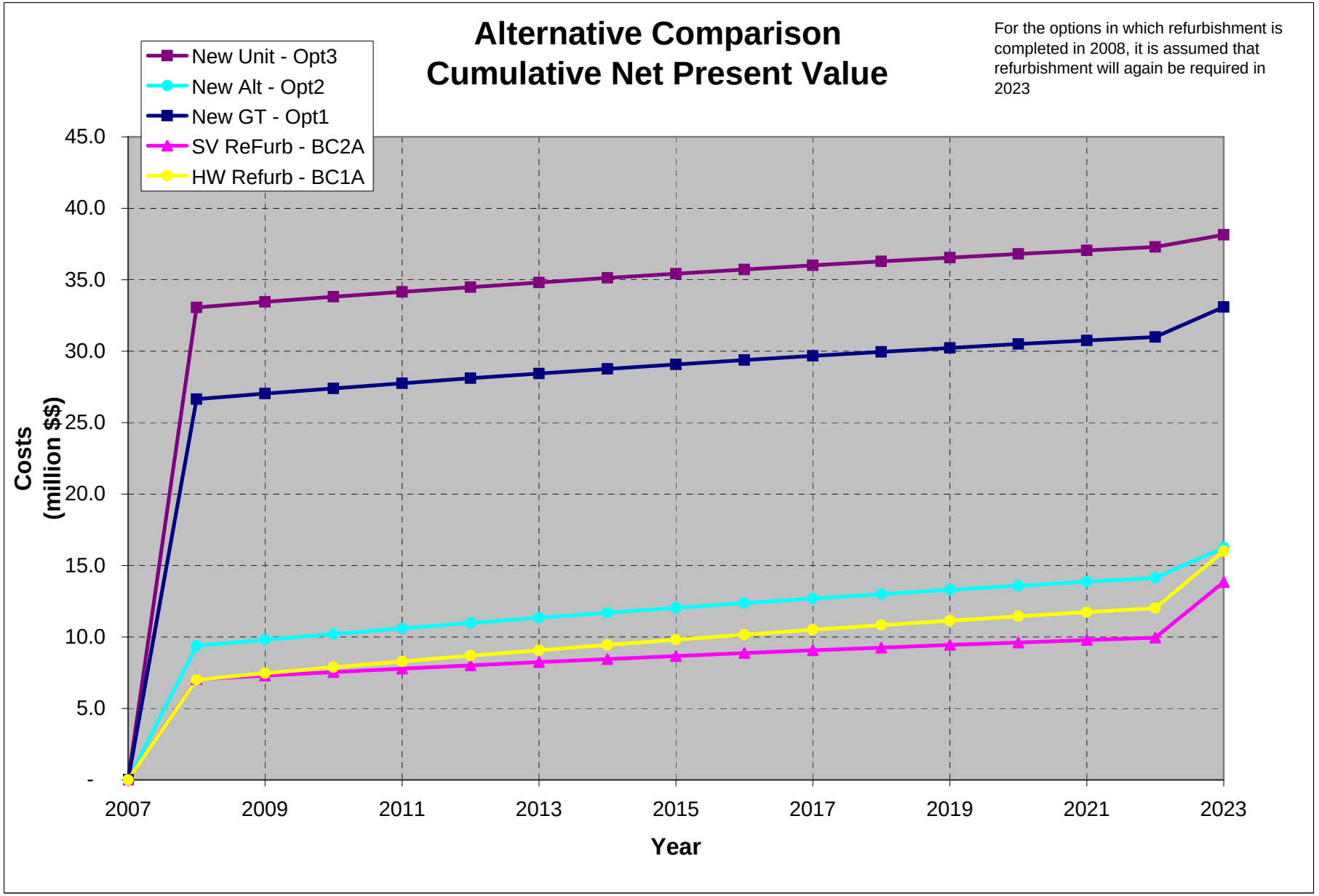
| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 37,859,400 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 2,000,000 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 37,859,400 | - | - | 37,859,400 | 33,067,866 | 33,067,866 |
| 2 | 2009 | 211,246 | 0.55 | 252,074 | - | 463,320 | - | - | 463,320 | 378,208 | 33,446,074 |
| 3 | 2010 | 216,105 | 0.56 | 254,358 | - | 470,462 | - | - | 470,462 | 358,914 | 33,804,987 |
| 4 | 2011 | 221,075 | 0.58 | 263,947 | - | 485,023 | - | - | 485,023 | 345,814 | 34,150,802 |
| 5 | 2012 | 226,602 | 0.61 | 276,734 | - | 503,336 | - | - | 503,336 | 335,394 | 34,486,196 |
| 6 | 2013 | 232,267 | 0.63 | 288,150 | - | 520,417 | - | - | 520,417 | 324,090 | 34,810,285 |
| 7 | 2014 | 238,074 | 0.67 | 304,133 | - | 542,207 | - | - | 542,207 | 315,569 | 35,125,855 |
| 8 | 2015 | 244,026 | 0.69 | 313,266 | - | 557,292 | - | - | 557,292 | 303,130 | 35,428,985 |
| 9 | 2016 | 250,126 | 0.72 | 329,249 | - | 579,376 | - | - | 579,376 | 294,525 | 35,723,510 |
| 10 | 2017 | 256,379 | 0.75 | 342,949 | - | 599,328 | - | - | 599,328 | 284,737 | 36,008,246 |
| 11 | 2018 | 262,789 | 0.79 | 358,932 | - | 621,721 | - | - | 621,721 | 276,051 | 36,284,298 |
| 12 | 2019 | 269,359 | 0.82 | 372,632 | - | 641,990 | - | - | 641,990 | 266,403 | 36,550,701 |
| 13 | 2020 | 276,093 | 0.85 | 386,788 | - | 662,881 | - | - | 662,881 | 257,077 | 36,807,777 |
| 14 | 2021 | 282,995 | 0.87 | 395,921 | - | 678,916 | - | - | 678,916 | 246,070 | 37,053,848 |
| 15 | 2022 | 290,070 | 0.88 | 402,771 | - | 692,841 | - | - | 692,841 | 234,689 | 37,288,537 |
| 16 | 2023 | 297,322 | 0.90 | 410,991 | - | 2,708,312 | - | - | 2,708,312 | 857,382 | 38,145,919 |
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Assumptions & Notes:

-New complete unit
-Does not include allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 70% of historical average
-Allowance for major maintenance included in 2023 (reflected as replacement cost)

| | | |
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Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that refurbishment will again be required in 2023
New Unit - Opt3
New Alt - Opt2
New GT - Opt1
SV ReFurb - BC2A
HW Refurb - BC1A
Costs (million $$)
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
2007
2009
2011
2013
2015
2017
2019
2021
2023
Year

# Hardwoods/Stephenville GT's (Options Subcase 1)

## Alternative Comparison

***Cumulative Net Present Value***
***To The Year***
**2023**

| Alternatives | Cumulative Net Present Value (CPW) | CPW Difference between Alternative and the Least Cost Alternative |
|---|---|---|
| Hardwoods Refurb - Base Case 1A | 16,010,747 | 2,167,979 |
| Stephenville Refurb - Base Case 2A | 13,842,768 | 0 |
| New GT/Refurb Alt - Option 1 | 33,088,681 | 19,245,913 |
| New Alt/Refurb GT - Option 2 | 16,248,954 | 2,406,186 |
| New Unit Complete - Option 3 | 38,145,919 | 24,303,151 |

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# Project Cost/Benefit Analysis Template

## Home Page

Current year
2007

| | |
|---|---|
| **Project Title** | Hardwoods/Stephenville GT's (Options Subcase 2) |
| **Project In-Service Year** | 2008 |
| **Number of Years in Study Analysis** | 16 |
| **Discount Rate** | 7.0% |
| **Present Worth Year** | 2007 |

**(costs are present worthed to January of that year)**

Print Home Page

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**Hardwoods Refurb - Base Case 1A**
**HW ReFurb - BC1A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,017,554 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,017,554 | - | - | 8,017,554 | 7,002,842 | 7,002,842 |
| 2 | 2009 | 271,602 | 0.55 | 280,083 | - | 551,685 | - | - | 551,685 | 450,339 | 7,453,181 |
| 3 | 2010 | 277,849 | 0.56 | 282,620 | - | 560,469 | - | - | 560,469 | 427,579 | 7,880,760 |
| 4 | 2011 | 284,240 | 0.58 | 293,275 | - | 577,514 | - | - | 577,514 | 411,760 | 8,292,520 |
| 5 | 2012 | 291,346 | 0.61 | 307,482 | - | 598,827 | - | - | 598,827 | 399,024 | 8,691,544 |
| 6 | 2013 | 298,629 | 0.63 | 320,167 | - | 618,796 | - | - | 618,796 | 385,355 | 9,076,899 |
| 7 | 2014 | 306,095 | 0.67 | 337,926 | - | 644,021 | - | - | 644,021 | 374,826 | 9,451,725 |
| 8 | 2015 | 313,747 | 0.69 | 348,074 | - | 661,821 | - | - | 661,821 | 359,987 | 9,811,712 |
| 9 | 2016 | 321,591 | 0.72 | 365,833 | - | 687,423 | - | - | 687,423 | 349,451 | 10,161,163 |
| 10 | 2017 | 329,631 | 0.75 | 381,054 | - | 710,685 | - | - | 710,685 | 337,641 | 10,498,804 |
| 11 | 2018 | 337,871 | 0.79 | 398,813 | - | 736,685 | - | - | 736,685 | 327,097 | 10,825,901 |
| 12 | 2019 | 346,318 | 0.82 | 414,035 | - | 760,353 | - | - | 760,353 | 315,520 | 11,141,421 |
| 13 | 2020 | 354,976 | 0.85 | 429,764 | - | 784,741 | - | - | 784,741 | 304,336 | 11,445,757 |
| 14 | 2021 | 363,851 | 0.87 | 439,912 | - | 803,763 | - | - | 803,763 | 291,321 | 11,737,077 |
| 15 | 2022 | 372,947 | 0.88 | 447,523 | - | 820,470 | - | - | 820,470 | 277,922 | 12,014,999 |
| 16 | 2023 | 382,271 | 0.90 | 456,656 | - | 56,478,545 | - | - | 56,478,545 | 17,879,661 | 29,894,660 |
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes complete new unit required in 2023 (reflected as replacement cost)

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**Stephenville Refurb - Base Case 2A**
**SV ReFurb - BC2A**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 8,050,389 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 55,639,618 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 8,050,389 | - | - | 8,050,389 | 7,031,522 | 7,031,522 |
| 2 | 2009 | 157,035 | 0.61 | 165,489 | - | 322,524 | - | - | 322,524 | 263,276 | 7,294,797 |
| 3 | 2010 | 160,647 | 0.62 | 167,109 | - | 327,755 | - | - | 327,755 | 250,043 | 7,544,840 |
| 4 | 2011 | 164,341 | 0.64 | 172,778 | - | 337,120 | - | - | 337,120 | 240,362 | 7,785,202 |
| 5 | 2012 | 168,450 | 0.67 | 180,337 | - | 348,787 | - | - | 348,787 | 232,412 | 8,017,614 |
| 6 | 2013 | 172,661 | 0.69 | 187,356 | - | 360,018 | - | - | 360,018 | 224,201 | 8,241,814 |
| 7 | 2014 | 176,978 | 0.73 | 197,075 | - | 374,053 | - | - | 374,053 | 217,702 | 8,459,517 |
| 8 | 2015 | 181,402 | 0.75 | 203,014 | - | 384,417 | - | - | 384,417 | 209,097 | 8,668,614 |
| 9 | 2016 | 185,937 | 0.79 | 212,733 | - | 398,670 | - | - | 398,670 | 202,664 | 8,871,278 |
| 10 | 2017 | 190,586 | 0.82 | 221,372 | - | 411,958 | - | - | 411,958 | 195,718 | 9,066,996 |
| 11 | 2018 | 195,350 | 0.86 | 231,091 | - | 426,441 | - | - | 426,441 | 189,345 | 9,256,341 |
| 12 | 2019 | 200,234 | 0.89 | 239,730 | - | 439,964 | - | - | 439,964 | 182,569 | 9,438,910 |
| 13 | 2020 | 205,240 | 0.92 | 248,099 | - | 453,339 | - | - | 453,339 | 175,813 | 9,614,723 |
| 14 | 2021 | 210,371 | 0.94 | 254,038 | - | 464,409 | - | - | 464,409 | 168,323 | 9,783,046 |
| 15 | 2022 | 215,630 | 0.96 | 258,357 | - | 473,988 | - | - | 473,988 | 160,556 | 9,943,602 |
| 16 | 2023 | 221,021 | 0.98 | 264,567 | - | 56,125,206 | - | - | 56,125,206 | 17,767,803 | 27,711,405 |
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Assumptions & Notes:

-Refurbishment of engines, alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 90% of historical average
-Assumes complete new unit required in 2023 (reflected as replacement cost)

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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**New GT/Refurb Alt - Option1**
**New GT - Opt1**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 30,500,170 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 15,788,505 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 30,500,170 | - | - | 30,500,170 | 26,640,030 | 26,640,030 |
| 2 | 2009 | 226,335 | 0.55 | 252,074 | - | 478,409 | - | - | 478,409 | 390,525 | 27,030,554 |
| 3 | 2010 | 231,541 | 0.56 | 254,358 | - | 485,898 | - | - | 485,898 | 370,690 | 27,401,244 |
| 4 | 2011 | 236,866 | 0.58 | 263,947 | - | 500,814 | - | - | 500,814 | 357,073 | 27,758,317 |
| 5 | 2012 | 242,788 | 0.61 | 276,734 | - | 519,522 | - | - | 519,522 | 346,179 | 28,104,496 |
| 6 | 2013 | 248,858 | 0.63 | 288,150 | - | 537,008 | - | - | 537,008 | 334,421 | 28,438,918 |
| 7 | 2014 | 255,079 | 0.67 | 304,133 | - | 559,212 | - | - | 559,212 | 325,467 | 28,764,385 |
| 8 | 2015 | 261,456 | 0.69 | 313,266 | - | 574,722 | - | - | 574,722 | 312,611 | 29,076,995 |
| 9 | 2016 | 267,992 | 0.72 | 329,249 | - | 597,242 | - | - | 597,242 | 303,607 | 29,380,603 |
| 10 | 2017 | 274,692 | 0.75 | 342,949 | - | 617,641 | - | - | 617,641 | 293,437 | 29,674,040 |
| 11 | 2018 | 281,560 | 0.79 | 358,932 | - | 640,491 | - | - | 640,491 | 284,386 | 29,958,426 |
| 12 | 2019 | 288,599 | 0.82 | 372,632 | - | 661,230 | - | - | 661,230 | 274,387 | 30,232,813 |
| 13 | 2020 | 295,814 | 0.85 | 386,788 | - | 682,601 | - | - | 682,601 | 264,725 | 30,497,537 |
| 14 | 2021 | 303,209 | 0.87 | 395,921 | - | 699,130 | - | - | 699,130 | 253,397 | 30,750,934 |
| 15 | 2022 | 310,789 | 0.88 | 402,771 | - | 713,560 | - | - | 713,560 | 241,707 | 30,992,642 |
| 16 | 2023 | 318,559 | 0.90 | 410,991 | - | 16,518,055 | - | - | 16,518,055 | 5,229,193 | 36,221,835 |
| | | | | | | - | | | - | - | - |
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Assumptions & Notes:

-New engines, refurbishment of alternator and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 75% of historical average
-Assumes replacement of alternator required in 2023 (reflected as replacement cost)

| | | |
|---|---|---|
| Date Revised | | |
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**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**
**New Alt/Refurb GT - Option 2**
**New Alt - Opt2**

***Note: Costs are shown as positive values;Benefits as negative values***

| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 10,743,124 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 44,824,213 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 10,743,124 | - | - | 10,743,124 | 9,383,461 | 9,383,461 |
| 2 | 2009 | 241,424 | 0.55 | 280,083 | - | 521,507 | - | - | 521,507 | 425,705 | 9,809,165 |
| 3 | 2010 | 246,977 | 0.56 | 282,620 | - | 529,596 | - | - | 529,596 | 404,027 | 10,213,192 |
| 4 | 2011 | 252,657 | 0.58 | 293,275 | - | 545,932 | - | - | 545,932 | 389,242 | 10,602,434 |
| 5 | 2012 | 258,974 | 0.61 | 307,482 | - | 566,456 | - | - | 566,456 | 377,453 | 10,979,888 |
| 6 | 2013 | 265,448 | 0.63 | 320,167 | - | 585,615 | - | - | 585,615 | 364,692 | 11,344,579 |
| 7 | 2014 | 272,084 | 0.67 | 337,926 | - | 610,010 | - | - | 610,010 | 355,031 | 11,699,611 |
| 8 | 2015 | 278,886 | 0.69 | 348,074 | - | 626,960 | - | - | 626,960 | 341,025 | 12,040,635 |
| 9 | 2016 | 285,859 | 0.72 | 365,833 | - | 651,691 | - | - | 651,691 | 331,287 | 12,371,922 |
| 10 | 2017 | 293,005 | 0.75 | 381,054 | - | 674,059 | - | - | 674,059 | 320,241 | 12,692,163 |
| 11 | 2018 | 300,330 | 0.79 | 398,813 | - | 699,143 | - | - | 699,143 | 310,428 | 13,002,591 |
| 12 | 2019 | 307,838 | 0.82 | 414,035 | - | 721,874 | - | - | 721,874 | 299,552 | 13,302,143 |
| 13 | 2020 | 315,534 | 0.85 | 429,764 | - | 745,299 | - | - | 745,299 | 289,040 | 13,591,183 |
| 14 | 2021 | 323,423 | 0.87 | 439,912 | - | 763,335 | - | - | 763,335 | 276,668 | 13,867,850 |
| 15 | 2022 | 331,508 | 0.88 | 447,523 | - | 779,032 | - | - | 779,032 | 263,885 | 14,131,735 |
| 16 | 2023 | 339,796 | 0.90 | 456,656 | - | 45,620,665 | - | - | 45,620,665 | 14,442,334 | 28,574,070 |
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Assumptions & Notes:

-New alternator, refurbishment of engines and BOP
-Includes allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption
-O&M costs based on 80% of historical average
-Assumes replacement of engines/turbines required in 2023 (reflected as replacement cost)

| | | |
|---|---|---|
| Date Revised | | |
| Date Printed | 17-Dec-2007 | 11:43 AM |

**PROJECT COST / BENEFIT ANALYSIS TEMPLATE**

**Hardwoods/Stephenville GT's (Options**

**New Unit Complete - Option 3**

**New Unit - Opt3**

***Note: Costs are shown as positive values;Benefits as negative values***

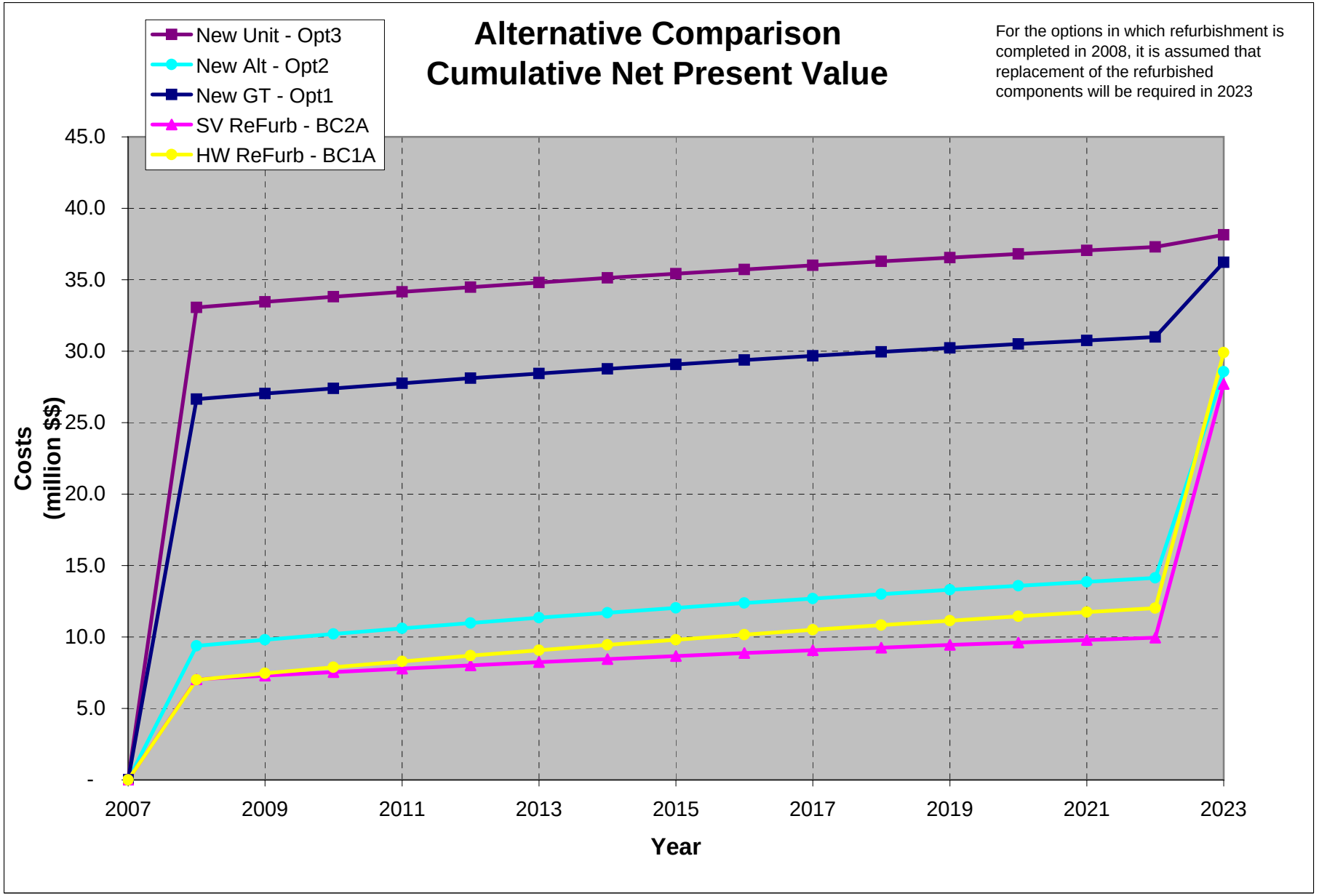
| | |
|---|---|
| Current Year | **2007** |
| Present Worth Year | 2007 |
| Number of Years in Study | 16 |
| Discount Rate | 7.0% |
| Total In-service Project Cost | $ 37,859,400 |
| In-service Year | 2008 |
| Other Project Cost ***after*** In-service (if applicable) | |
| Other Project Year (if applicable) | |
| Replacement Cost (if applicable) | $ 2,000,000 |
| Replacement Year (if applicable) | 2023 |
| Project cost in Ending (**E**) or Beginning (**B**) Year $$ | E |
| O&M costs - 75% Materials, 25% Labour (**75**) or 50% Materials, 50% Labour (**50**) or User (**U**) | 50 |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | Annual O&M Cost $ | Annual Fuel Price (if applicable) | Annual Fuel Cost $ | Other Cost $ | Total Costs $ | Benefit 1 *(specify)* $ | Benefit 2 *(specify)* $ | NET $ | P.W. January 2007 | Cumulative Present Worth |
| 0 | 2007 | - | | - | - | - | - | - | - | - | - |
| 1 | 2008 | - | | - | - | 37,859,400 | - | - | 37,859,400 | 33,067,866 | 33,067,866 |
| 2 | 2009 | 211,246 | 0.55 | 252,074 | - | 463,320 | - | - | 463,320 | 378,208 | 33,446,074 |
| 3 | 2010 | 216,105 | 0.56 | 254,358 | - | 470,462 | - | - | 470,462 | 358,914 | 33,804,987 |
| 4 | 2011 | 221,075 | 0.58 | 263,947 | - | 485,023 | - | - | 485,023 | 345,814 | 34,150,802 |
| 5 | 2012 | 226,602 | 0.61 | 276,734 | - | 503,336 | - | - | 503,336 | 335,394 | 34,486,196 |
| 6 | 2013 | 232,267 | 0.63 | 288,150 | - | 520,417 | - | - | 520,417 | 324,090 | 34,810,285 |
| 7 | 2014 | 238,074 | 0.67 | 304,133 | - | 542,207 | - | - | 542,207 | 315,569 | 35,125,855 |
| 8 | 2015 | 244,026 | 0.69 | 313,266 | - | 557,292 | - | - | 557,292 | 303,130 | 35,428,985 |
| 9 | 2016 | 250,126 | 0.72 | 329,249 | - | 579,376 | - | - | 579,376 | 294,525 | 35,723,510 |
| 10 | 2017 | 256,379 | 0.75 | 342,949 | - | 599,328 | - | - | 599,328 | 284,737 | 36,008,246 |
| 11 | 2018 | 262,789 | 0.79 | 358,932 | - | 621,721 | - | - | 621,721 | 276,051 | 36,284,298 |
| 12 | 2019 | 269,359 | 0.82 | 372,632 | - | 641,990 | - | - | 641,990 | 266,403 | 36,550,701 |
| 13 | 2020 | 276,093 | 0.85 | 386,788 | - | 662,881 | - | - | 662,881 | 257,077 | 36,807,777 |
| 14 | 2021 | 282,995 | 0.87 | 395,921 | - | 678,916 | - | - | 678,916 | 246,070 | 37,053,848 |
| 15 | 2022 | 290,070 | 0.88 | 402,771 | - | 692,841 | - | - | 692,841 | 234,689 | 37,288,537 |
| 16 | 2023 | 297,322 | 0.90 | 410,991 | - | 2,708,312 | - | - | 2,708,312 | 857,382 | 38,145,919 |
| | | | | | | - | | | - | - | - |
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Assumptions & Notes:

-New complete unit
-Does not include allowance for rental mobile equipment during refurbishment period
-Fuel costs based on HYDRO price forecast and historical consumption, with an adjustment for improved efficiency of new engines (10%)
-O&M costs based on 70% of historical average
-Allowance for major maintenance included in 2023 (reflected as replacement cost)

| | | |
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Alternative Comparison
Cumulative Net Present Value
For the options in which refurbishment is completed in 2008, it is assumed that replacement of the refurbished components will be required in 2023
New Unit - Opt3
New Alt - Opt2
New GT - Opt1
SV ReFurb - BC2A
HW ReFurb - BC1A
Costs (million $$)
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
2007
2009
2011
2013
2015
2017
2019
2021
2023
Year

# Hardwoods/Stephenville GT's (Options Subcase 2)

## Alternative Comparison

***Cumulative Net Present Value***
***To The Year***
**2023**

| Alternatives | Cumulative Net Present Value (CPW) | CPW Difference between Alternative and the Least Cost Alternative |
|---|---|---|
| Hardwoods Refurb - Base Case 1A | 29,894,660 | 2,183,255 |
| Stephenville Refurb - Base Case 2A | 27,711,405 | 0 |
| New GT/Refurb Alt - Option1 | 36,221,835 | 8,510,430 |
| New Alt/Refurb GT - Option 2 | 28,574,070 | 862,665 |
| New Unit Complete - Option 3 | 38,145,919 | 10,434,515 |

| | | |
|---|---|---|
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| Date Revised: | | |

# APPENDIX 13
# PHOTOGRAPHS
# HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES



**HWD-001 – Gas Turbine**

**Newfoundland and Labrador Hydro**
**St. John's, NL**

# HARDWOODS



HWD-002 – Air Inlet & Exhaust



HWD-004 – Air Inlet



HWD-003 – Air Inlet



HWD-005 – Air Inlet



HWD-006 – Air Inlet



HWD-007 – Air Inlet



HWD-008 – Air Inlet



HWD-009 – Air Inlet



HWD-010 – Air Inlet



HWD-011 – Exhaust Stack



HWD-012 – Exhaust Stack



HWD-013 – Exhaust Stack



HWD-014 – Exhaust Stack



HWD-015 – Exhaust Stack



HWD-016 – Exhaust Stack



HWD-017 – Exhaust Stack



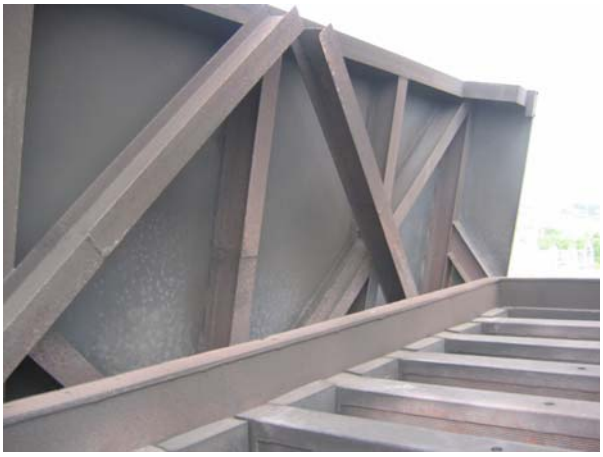
HWD-018– Exhaust Stack



HWD-019 – Exhaust Stack



HWD-020– Exhaust Stack



HWD-021– Exhaust Stack



HWD-022– Exhaust Stack



HWD-023– Lube Oil Glycol Cooler



HWD-024– Lube Oil Glycol Cooler



HWD-025 – Engine & Turbine Enclosure



HWD-026 – Engine & Turbine Enclosure



HWD-027 – Alternator Enclosure



HWD-028 – Oil Storage Area



HWD-029 – Oil Storage Area



HWD-030 – Oil Storage Tank



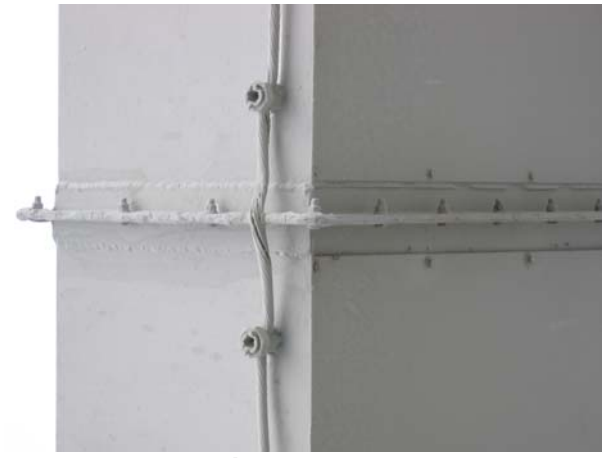
HWD-031 – Oil Storage Tank



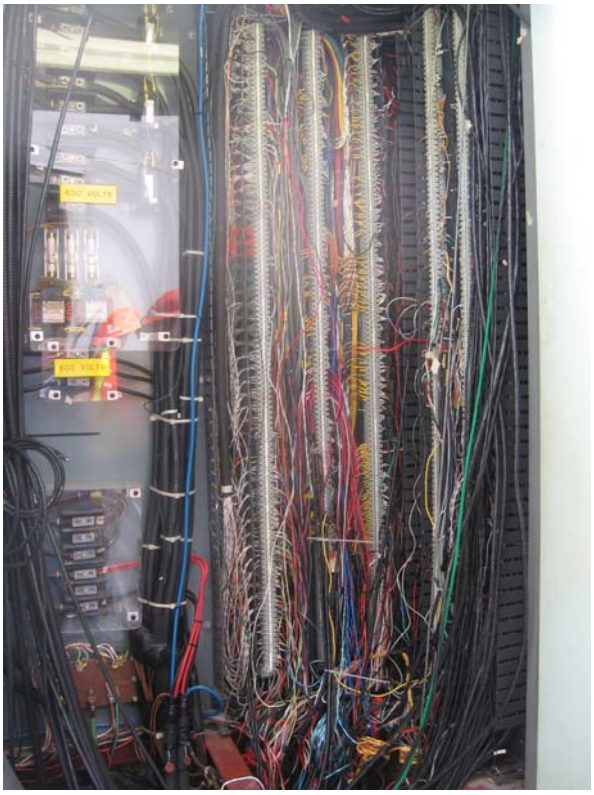
HWD-032 – 13.8 kV Bus Duct



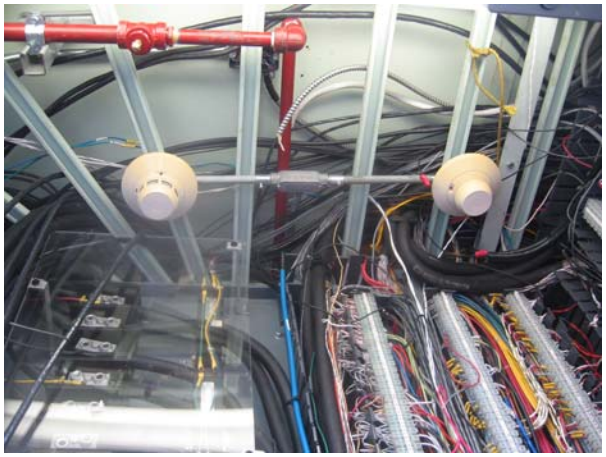
HWD-033 – 13.8 kV Bus Duct



HWD-034 – 13.8 kV Bus Duct



HWD-035 – Control Module Cabling



HWD-036 – Control Module Cabling



HWD-037 – Control Module Building



HWD-038 – Control Module Building



HWD-039 – Fuel Unloading Building



HWD-040 – Fuel Unloading Building



HWD-041 – Fuel Unloading Building



HWD-042 – Fuel Unloading Building



HWD-043 – Fuel Forwarding Building



HWD-044 – Fuel Forwarding Building



HWD-045 – Fuel Forwarding Building



HWD-046 – Auxiliary Module Building



HWD-047 – Maintenance Building



HWD-048 – HV Switchgear Building



**SVL-001 – Gas Turbine**

**Newfoundland and Labrador Hydro**
**St. John's, NL**

**STEPHENVILLE**



SVL-002 – Air Inlet



SVL-003 – Air Inlet



SVL-004 – Air Inlet



SVL-005 – Air Inlet



SVL-006 – Air Inlet



SVL-007 – Air Inlet



SVL-008 – Exhaust Stack



SVL-009 – Exhaust Stack



SVL-010 – Exhaust Stack



SVL-011 – Exhaust Stack



SVL-012 – Lube Oil Glycol Cooler



SVL-013 – Lube Oil Glycol Cooler



SVL-014 – Lube Oil Glycol Cooler



SVL-016 – Engine & Turbine Enclosure



SVL-015 – Engine & Turbine Enclosure



SVL-017 – Engine & Turbine Enclosure



SVL-018– Engine & Turbine Enclosure



SVL-019 – Alternator Enclosure



SVL-020– Alternator Glycol Cooler



SVL-021– Alternator Glycol Cooler



SVL-022– Alternator Glycol Cooler



SVL-023– Alternator Glycol Cooler



SVL-024–Oil Storage Area



SVL-025 – Oil Storage Area



SVL-026 – Oil Storage Area



SVL-027 – Oil Storage Piping



SVL-028 – HV Switchgear Building



SVL-029 – 13.8 kV Bus Duct



SVL-030 – 13.8 kV Bus Duct



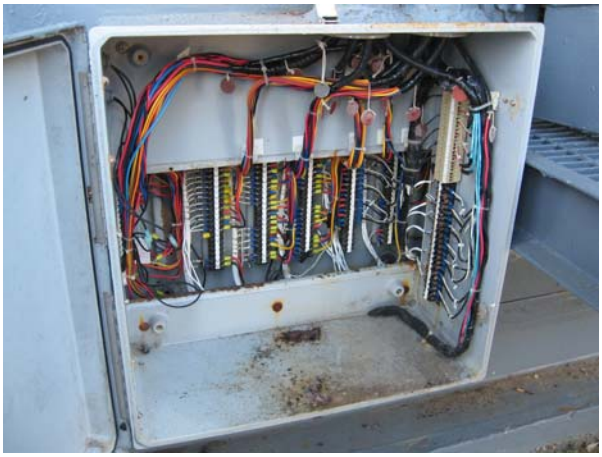
SVL-031 – Battery Chargers



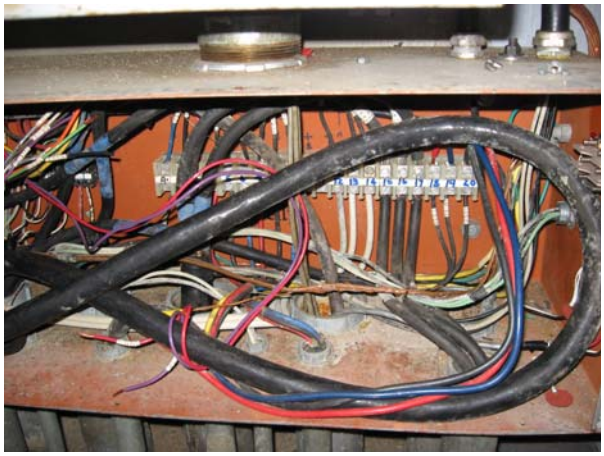
SVL-032 – Protection Relays



SVL-033 – 15 kV Transformer Cabling



SVL-034 – GT Junction Box



SVL-035 – GT Junction Box



SVL-036 – Control Building



SVL-037 – Control Building



SVL-038 – Control Building



SVL-039 – Control Building



SVL-040 – Fuel Forwarding Building



SVL-041 – Fuel Forwarding Building



SVL-042 – Fuel Forwarding Building



SVL-043 – Fuel Forwarding Building



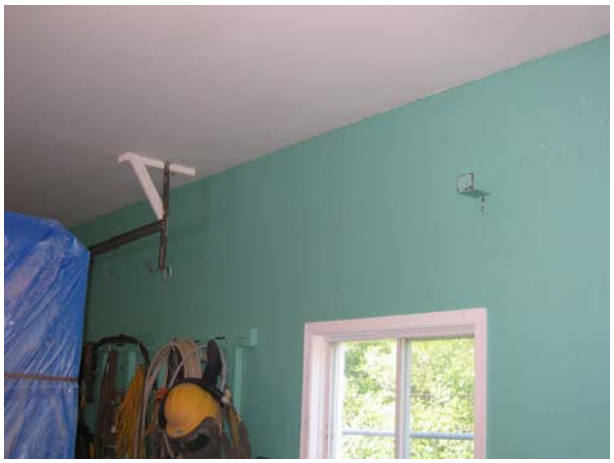
SVL-044 – Parts Storage Shed



SVL-045 – Parts Storage Shed



SVL-046 – Parts Storage Shed



SVL-047 – Parts Storage Shed



SVL-048 – Waste Oil Storage Shed




SVL-049 – Waste Oil Storage Shed

19 December 2011

Mr. Todd Collins, P. Eng.
Mechanical Design Engineer, Engineering Services
NALCOR Energy
Hydro Place, 500 Columbus Drive
PO Box 12400
St John's, NL, Canada
A1B 4K7

Dear Todd,

Holyrood Thermal Generating Station (Holyrood) Gas Turbine Condition Assessment & Options Study – Final Report

As per our Agreement, we have completed the Holyrood Thermal Generating Station Gas Turbine Condition Assessment. I trust that the report satisfies your needs.

Thank you for the opportunity to work on this very interesting project.

Yours truly,

Blair Seckington
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# Holyrood Thermal Generating Station

# Gas Turbine Condition Assessment & Options Study

**December 19, 2011**

## Holyrood Thermal Generating Station
## Gas Turbine Condition Assessment & Options Study

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# HOLYROOD THERMAL GENERATING STATION
# GAS TURBINE CONDITION ASSESSMENT & OPTIONS STUDY

## EXECUTIVE SUMMARY

The Holyrood gas turbine generator is a nominally 13.5 MW packaged generating unit system. It serves as a black start unit for the station and is occasionally used for system support. Due to the critical nature of the role that the Holyrood GT plays, it must operate with a high degree of operational reliability.

The gas turbine went in service at Holyrood in 1986. As of December 2010, the unit had a total of approximately 4717 operating hours, +386,000 idle hours, and 2548 starts. Due to the age of the gas turbine and balance of plant, the large number of idle hours, and its exposure to a marine environment, it was necessary to perform a comprehensive condition assessment and life extension study. In general, the unit and balance of plant equipment requires refurbishment or replacement work to continue operating with a high degree of reliability to its required end of life of 2020. The study will identify the measures that need to be taken to ensure reliable operation of the gas turbine (GT) and balance of plant. AMEC Americas Limited (AMEC) was contracted by NL Hydro to conduct a Condition Assessment and Refurbishment/Replacement Study for the Holyrood BlackStart Gas Turbine Generator and balance of plant equipment.

The scope of work consists of an engineering study that will assess the condition of the Holyrood Thermal Generating Station (HTGS) gas turbine and balance of plant and make recommendations for work including cost estimates that will be required to extend its useful life to 2020 with the same high degree of reliability as that experienced in the past. The engineering study will include a Level 2 study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three level methodology for performing condition assessment and life extension studies within the utilities industry in which the level of sophistication and detail increases progressively through Level I, Level II, and Level lll studies. AMEC shall apply this process to the gas turbine generator and balance of plant equipment.

Part A of the study is primarily a detailed condition assessment and refurbishment study of the existing gas turbine plant located at HTGS with recommendations and cost estimates to extend the life of the gas turbine plant as a highly reliable operation to the year 2020.

Part B of the study examines the replacement of the existing gas turbine plant with a new or good used mobile generating plant considering either:

a) A GT plant consisting of two 5 MW mobile/transportable units.

b) A diesel generating plant consisting of five 2 MW diesel units.

As a result of the assessment, AMEC makes the following conclusions and recommendations:

### ASSESSMENT BASIS

1. A black-start installation of ten (10) megawatts (MW) is required at the Holyrood Thermal Generating Station site to ensure the capability of the Holyrood units to quickly return to service in the event of a major system failure.
2. The black-start capability must be maintained during any refurbishment or replacement period. This particularly impacts the existing GTG refurbishment option since refurbishment of the existing unit may take an outage of months during which another standby generation unit may be needed and its costs borne by the project. For the existing unit, the lease cost can vary from about $170,000 for the

lease of a reconditioned gas generator and power turbine to swap into the existing unit to about $4.7 million for the lease of a complete 10 MW portable/transportable installation including all associated balance of plant systems and installation.

3. Each of the options has a "terminal value" at the end of the 2020 period. The amount is a function of both the age and condition and market value of the units at that time, and/or of its internal value for redeployment for other uses within Hydro post 2020 (i.e. regional distribution line outage/maintenance support). Potential short term alternative uses prior to 2020 may also have value, but were not assessed.

**TERMINAL VALUES IN 2020**

| Option | Purchased Equipment Cost M$ | System Terminal Value in 2020 M$ | Comment |
|---|---|---|---|
| Option 0 - Refurbished Existing Unit | $3.0 | $0 | Terminal value covers cost for demolition |
| Option 1 - New 2 x 5 MW GT | $10.9 | $7.0 | Low use, essentially new condition. |
| Option 1A - Nearly New 2 x 5 MW GT | $9.2 | $4.0 | Lower percent recovery than new given prior use. |
| Option 2 - New 5 x 2 MW Diesel Genset | $8.6 | $5.0 | Lower market value – more available. |
| Option 2A - Nearly New 5 x 2 MW Diesel Genset | $7.5 | $3.0 | Lower percent recovery than new given prior use. |

4. The system failure cost" of each of the options during the period to the end of 2020. This is a function of the expected or predicted difference in reliability between the options and the cost per hour of electric system black-out/disruption. The situation assumed to occur would be similar to the 1986 island blackout which lasted about 30 hours

**ECONOMIC VALUES – FAILURE TO OPERATE ASSUMPTIONS**

| **Failure To Operate** | | % Probability once over 2013-2020 | Value of Hr Shutdown | # Hrs Per Shutdown | Probable $/Incident |
|---|---|---|---|---|---|
| | | % (A) | MM$/Hr (B) | Hrs (C) | MM$ (D) = AxBxC |
| Option 0 | Refurbished Unit | 10% | $5 | 20 | $10 |
| Option1 & 1A | New/Used 2 x 5 MW GT | 0% | $5 | 20 | $0 |
| Option 2 & 2A | New/Used 5x2 MW Diesel | 4% | $5 | 20 | $4 |

**Notes:**
Value/ Hr Shutdown = $5 MM (Impact to Newfoundland Economy)
Probability risk is relative to the new 2 x 5MW GT option
One occurrence assumed nominally in 2016
Probable $/incident increases proportional to (A), (B), or (C)

## CONCLUSIONS

### Existing Gas Turbine Generator Unit

1. The existing GT generator should not be operated (started, operated, shutdown) except in an emergency situation, and in such an emergency its operation should be observe remotely to ensure personnel safety.
    i) Fire from lube oil system gearbox seals remains a possible safety issue.
    ii) Catastrophic failure of the power turbine disk is a possibility due to corrosion and high stress that may be present at blade roots and attachments
2. The existing GT generator requires extensive overhaul and repair work:
    i) Power turbine disk may require replacement (9 month manufacturing lead time)
    ii) One or more power turbine blades may require replacement or significant repair
    iii) Gas generator blading requires cleaning and recoating
    iv) Inlet filter media requires replacement and inlet duct requires refurbishment (including cooling air duct to power turbine disk)
    v) Exhaust stack requires replacement or extensive repairs
    vi) Gearbox lube oil system requires modification and refurbishment
        a. Seals require replacement/modification
        b. Venting system modifications required to reduce lube oil pressure buildup
        c. Lube oil pump system requires upgrade for start-ups.
        d. Lube oil cooling fan is experiencing some leaks and snow and ice and water build-ups in its containment can cause start-issues
    vii) Gearbox bearings likely worn and need refurbishment or replacement and/or unit re-alignment
    viii) Unit generator requires significant testing and possibly rewind
    ix) Unit generator exciter needs refurbishment and likely replacement
3. GT electrical and controls system has elements that are not in compliance with current standards and/or are obsolete and hence necessitates replacement:
    i) Unit AVR
    ii) Unit MCC's
4. The GT and generator enclosure rooms require modification to their fire detection and suppression systems to provide better coverage, as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010.
5. GT fuel oil receiving, forwarding, and delivery system are in operable condition, but climatic conditions (icing, snow-buildup, water build-ups from rain, rusting from salty ambient air) result in significant periods where starts may fail or be significantly delayed. The GT generator building is in generally good condition, except for:
    i) Major leaks in and around the GT exhaust stack which are impacting the gas turbine power turbine volute and back end blades;
    ii) Minor leaks at generator ventilation stack; and
    iii) Minor air leaks as a result of minor siding holes (corrosion) which require repair/ refurbishment
6. The electrical services room require expansion to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash).

7. The earliest in-service dates for refurbishing the existing unit and returning it to service:
    a. Without back-up during the existing unit outage, but restricting the outage to lower risk, late spring to early fall periods is October 2013, with a roughly six month outage.
    b. With a nearly new 2 x 5 MW GT leased unit required during an existing unit outage is July 2013 with the existing unit on outage about five months.
    c. With shorter duration engineering and procurement times for BOP, fuel system and electrical systems, the in-service can theoretically be advance two to three months, but outage scheduling would likely mitigate this.

    Note: Using leased parts during outage, or procuring used parts and refurbishing them, has no significant positive impact.
8. The capital cost for refurbishing the existing unit is between $4.5 and $5 million, depending on the amount of additional work found during refurbishment. If leasing a replacement 2 x 5 MW unit is required to avoid any outage, then the total capital cost would be between $9.5 and $10.0 million, depending on the market price and availability of portable/mobile equipment. There is some opportunity to slightly reduce costs if used parts for the unit, and in particular the power turbine disk, are available.

**New and Nearly-New 2 x 5MW Portable/Transportable Gas Turbine Generator Units**

1. The two 5 MW transportable gas turbine units option is consistent with the requirements for black start power, the need to start a 3 MW power block (one boiler feed pump motor), and simplicity of managing the number of black start units in parallel.
2. The space requirements for the two 5 MW transportable gas turbine units (2 trailers each plus a common electrical building) cannot be accommodated in the existing GT area.
3. Space and civil requirements support the use of the existing well graded area behind the old security building as the best location.
4. Two new 5 MW transportable gas turbine units could be readily purchased, with a manufacturing time of about 12 months.
5. Two nearly new, used 5 MW transportable GT units may be possible to acquire to a shorter time. Their availability and cost are functions of the market place. The units may also have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
6. Emissions, particularly NOx emissions, will have to be addressed:
    i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
    ii) NOx emissions will be lower than those of the current GTG units, but being oil fuelled units will be challenged to meet Canadian Council of Ministers of the Environment (CCME gas turbine NOx emission guidelines
    iii) Newfoundland & Labrador environmental regulations require Best Available Control Technology (BACT), although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
        a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on the unit such as a limit on the number of operating hours per year.

7. Five MW units are likely the upper limit of useful unit size for redeployment in support of transmission and distribution line maintenance support either post 2020 or periods up to 2020.

8. The earliest in-service date for procuring and installing 2 x 5 MW new gas turbine generators is May 2013. The earliest in-service date for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is March 2013.

9. The capital cost for procuring and installing 2 x 5 MW new gas turbine generators is $13.3 million. The capital cost for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is $11.5 million.

**New and Nearly-New 5 x 2MW Portable/Transportable Diesel Engine Generator Units**

1. The five 2 MW transportable diesel engine generator units option is potentially consistent with the requirements for black start power, but:
   i) The units may have significant difficulty responding to a block load start of 3 MW power block (one boiler feed pump motor), and
   ii) Islanded synchronous operation during start-up of five units may be difficult to maintain and affect overall system capacity available and overall system start-up reliability. It will also likely require a more complex control system.

2. The space requirements for the five 2 MW transportable diesel engine generator units (5 trailers plus two electrical trailers plus a common electrical building) cannot be accommodated in the existing GT area.
   i) Space and civil requirements suggested that use of the existing well graded area behind the old security building was the best location.
   ii) Spacing requirements are increased by separation requirements between units

3. Five new 2 MW transportable diesel engine generator units could be readily purchased, with a manufacturing time of about 12 months.

4. Five nearly new, used 2 MW transportable diesel engine generator units may be possible to acquire to a shorter time. Their availability and cost are functions of the marketplace and the units may have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).

5. Emissions, particularly NOx emissions, will have to be addressed:
   i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
   ii) NOx emissions, particularly for some used engines, may not be lower than those of the existing GT unit. They will have higher emission levels than the GT options.
   iii) Applicable diesel engine generator emission regulations in the US and Canada are in flux, with significantly more stringent requirements likely for units coming into service in the 2012 through 2015 period. Emergency power non-mobile (i.e. not on road or off-road units) will face significant but less stringent levels, but will have their operation limited to emergency use only (in effect similar to the restriction imposed on the existing GT).
   iv) Newfoundland & Labrador environmental regulations require BACT, although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
      a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start

readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on its role and likely a limit on the number of operating hours per year.

6. Two MW units are good candidates for redeployment in support of transmission and distribution line maintenance support either post 2020 or in possible periods up to 2020. They are typical of larger unit sizes deployed for that purpose now.

7. The earliest in-service date for procuring and installing 5 x 2 MW new diesel gensets is May 2013. The earliest in-service date for procuring and installing 5 x 2 MW nearly new/used diesel gensets is March 2013.

8. The capital cost for procuring and installing 5 x 2 MW new diesel gensets is $10.8 million. The capital cost for procuring and installing 5 x 2 MW nearly new/used diesel gensets is $9.6 million.

**Overall Economics**

Using the Assessment Basis,

1. The base capital cost comparison of the options is as follows:

**BASE CAPITAL COST COMPARISON OF OPTIONS**

**Capital Cost Comparison**
**Capital cost estimate $1,000 Can 2011**

| Option Number | 0 | 1 | 1A | 2 | 2A |
|---|---|---|---|---|---|
| Option | Existing GT Refurb | New 2 x 5 MW GT | Used 2 x 5 MW GT | New 5 x 2 MW Diesel | Used 5 x 2 MW Diesel |
| GT/Diesel Cost | $2,950 | $10,865 | $9,234 | $8,553 | $7,453 |
| Civil Works | $224 | $131 | $131 | $131 | $131 |
| Electrical Works | $541 | $759 | $759 | $801 | $801 |
| BOP Systems | $330 | $129 | $129 | $129 | $129 |
| Existing Unit Demolition & Removal | $0 | $7 | $7 | $7 | $7 |
| **Sub-Total - Directs and Indirects** | $4,046 | $11,891 | $10,260 | $9,620 | $8,520 |
| Project Engineering | $324 | $625 | $544 | $513 | $458 |
| Project Management | $283 | $832 | $718 | $673 | $596 |
| Total | $4,652 | $13,348 | $11,522 | $10,807 | $9,575 |

| | |
|---|---|
| + Standby = Total | $4,825 |
| | |
| + New Rental Stdby = Total | $9,421 |

- The life cycle cost comparison of the options in 1) un-escalated non-discounted (not present worthed), 2) un-escalated discounted (present worthed), 3) escalated non-discounted (not present worthed), and 4) escalated discounted (present worthed) costs is as follows.

The existing unit refurbishment option costs include the lower cost standby option assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $170,000 to the base cost. The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly

new GT leased option would add an additional $4.7 M. The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million (2011 Cdn $) in 2016 for the existing GT and $4 million in 2016 for the 5 x 2 MW diesel options.

| | | Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $14,825 | $1,885 | $1,408 | $18,118 | ($1,648) | $16,470 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $11,454 | $1,291 | $959 | $13,704 | ($1,122) | $12,582 |
| 3 | ESCALATED CASHFLOW | $16,260 | $2,159 | $1,660 | $20,079 | ($1,943) | $18,136 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $11,521 | $1,302 | $992 | $13,815 | ($1,161) | $12,654 |

| | | Option 1 New 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $6,348 | $1,714 | $1,237 | $9,300 | ($1,648) | $7,652 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $8,766 | $1,175 | $842 | $10,783 | ($1,122) | $9,661 |
| 3 | ESCALATED CASHFLOW | $4,940 | $1,963 | $1,459 | $8,362 | ($1,943) | $6,419 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $8,731 | $1,185 | $871 | $10,787 | ($1,161) | $9,626 |

| | Option 1A Used 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $7,522 | $1,714 | $1,237 | $10,473 | ($1,648) | $8,826 |
| 2 | $8,632 | $1,175 | $842 | $10,649 | ($1,122) | $9,527 |
| 3 | $6,815 | $1,963 | $1,459 | $10,236 | ($1,943) | $8,294 |
| 4 | $8,618 | $1,185 | $871 | $10,674 | ($1,161) | $9,513 |

| | | Option 2 New 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $9,807 | $323 | $1,237 | $11,366 | ($1,648) | $9,719 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $10,231 | $220 | $842 | $11,293 | ($1,122) | $10,171 |
| 3 | ESCALATED CASHFLOW | $9,358 | $370 | $1,459 | $11,187 | ($1,943) | $9,244 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $10,232 | $222 | $871 | $11,325 | ($1,161) | $10,164 |

| | Option 2A Used 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $10,575 | $323 | $1,237 | $12,134 | ($1,648) | $10,487 |
| 2 | $10,128 | $220 | $842 | $11,190 | ($1,122) | $10,068 |
| 3 | $10,593 | $370 | $1,459 | $12,422 | ($1,943) | $10,479 |
| 4 | $10,143 | $222 | $871 | $11,236 | ($1,161) | $10,075 |

## RECOMMENDATIONS

1. The existing gas turbine generator should not be operated (started, operated, shut down), except in an emergency situation, and in such an emergency its operation should be observed remotely.
2. Using the Assessment Basis, the preferred option is Option 1, the 2 x 5 MW new GT installation.
3. Hydro should review the Assessment Basis and any impacts of changes in it as part of its internal decision-making process on the options.
4. Hydro should proceed with a preferred option as soon as practically possible, given that the likelihood of safely and successfully starting the existing GT unit in an emergency condition in its existing state is very poor and likely to decrease rapidly with time idle.
5. If Hydro internally chooses refurbishment of the existing GT generator as its preferred option, then the existing GT generator should undergo an extensive overhaul and repair program, including:

    i) Gas Turbine Unit

        a. Power turbine disk replacement (9 month manufacturing lead time);
        b. Power turbine damaged blades replacement (one or more) or significant repair;
        c. Gas generator blading cleaning and recoating;
        d. Inlet filter media replacement and inlet duct refurbishment (including cooling air duct to power turbine disk); and
        e. Exhaust stack replacement or extensive repairs

    ii) Gearbox lube oil system modification and refurbishment

        a. Seals replacement/modification;
        b. Venting system modifications to reduce lube oil pressure buildup;
        c. Lube oil pump system upgrade for start-ups; and

d. Lube oil cooling fan replacement

iii) Gearbox bearings refurbishment or replacement and/or unit re-alignment

iv) GT Generator testing and refurbishment

a. Unit generator electrical testing and possible rewind; and
b. Unit generator exciter testing, and refurbishment/replacement as necessary

v) GT electrical and controls system update to compliance with current standards and/or obsolescence replacement

a. Unit AVR
b. Unit MCC's

vi) The GT and generator enclosure rooms' fire detection and suppression systems modifications to provide better coverage (as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010).

vii) GT fuel oil receiving, forwarding, and delivery system replacement in an enclosed shed.

viii) GT generator building repairs:

a. Major leaks in and around the gas turbine exhaust stack
b. Minor leaks at generator ventilation stack
c. Minor air leaks as a result of minor siding holes (corrosion)

ix) Expansion of the electrical services room to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash)

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# GLOSSARY

| | |
|---|---|
| °F or oF | Degree Fahrenheit |
| °C or oC | Degree Celsius |
| ATS | Automatic Transfer Switch |
| BTU | British Thermal Unit |
| CO2 | Carbon dioxide |
| CW | Circulating or cooling water |
| DCS | Distributed Control System |
| DG | Diesel Generator |
| Gen | Generator (Only) |
| GTG | Gas Turbine Generator |
| HP | High Pressure |
| JB | Junction Box |
| kV | Kilovolt |
| kVAR | Kilovolt ampere reactive |
| kW | Kilowatt |
| kWh | Kilowatthour |
| LP | Low pressure |
| Max | Maximum |
| MCC | Motor control centre |
| MCR | Maximum continuous rating |
| mm | Millimetres |
| Mg | Megagrams |
| mg | Milligrams |
| MOT | Main output transformer |
| MTS | Manual Transfer Switch |
| MVA | Megavoltampere |
| MVAR | Megavolt ampere reactive |
| MW/MWg/MWn | Megawatt /megawatt gross/megawatt net |
| MWh/MWhg/MWhn | Megawatt hour/ megawatthour gross megawatthour net |
| Min | Minute |
| O2 or $O_2$ | Oxygen |
| psig or $psi_g$ | Pound per hour pounds per square inch gauge |
| psia or $psi_a$ | Pounds per square inch absolute |
| ppmvd or $ppm_{vd}$ | Parts per million (dry volume basis) |
| % | Percentage |
| PT | Power Turbine |
| Rpm | Revolutions per minute |
| Scfh | Standard cubic feet per hour |
| T9 | Transformer #9 |
| TGS | Thermal generating station |
| VAR | Vars |
| V | Volts |

# HOLYROOD THERMAL GENERATING STATION
# GAS TURBINE CONDITION ASSESSMENT & OPTIONS STUDY

## 1 INTRODUCTION

### 1.1 Holyrood Thermal Generating Station and Black Start Gas Turbine Generator

#### 1.1.1 Holyrood Thermal Generating Station (Holyrood)

Holyrood Thermal Generating Station is a three unit, nominally 500 MW, heavy oil fired, steam cycle fossil generating station. It is located on the south shore of Conception Bay in the province of Newfoundland and Labrador, between the towns of Holyrood and Conception Bay South. Holyrood was constructed in two stages - Units 1 and 2 in the late 1960's and Unit 3 in 1977.

When all three units are in operation at full MCR (maximum continuous rating), Holyrood is capable of supplying approximately 33% of the Newfoundland and Labrador electricity demand. Typically, the units operate during the late fall to spring peak period and supply a minimum load of between 80 MW and 150 MW. The Unit 3 generator is also capable of synchronous condenser operation for grid voltage control.

#### 1.1.2 Holyrood Black Start Gas Turbine Generator (GT)

The Holyrood gas turbine generator is a nominally 13.5 MW packaged generating unit system. It serves as a black start unit for the station and is occasionally used for system support. Due to the critical nature of the role that the Holyrood GT plays, it must operate with a high degree of operational reliability.

The gas turbine generator is comprised of a number of components: inlet plenum, AVON 1533-70L gas generator and power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system.

Ambient air enters the intake structure, passes through an intake air filter and enters the inlet air plenum. The air is compressed via a 17- stage axial flow compressor in the forward section of an AVON 1533-70L.gas generator. Fuel is supplied to an eight burner combustion section between the gas generator air compressor section and its turbine section. Combustion of the fuel results in a rapid increase in the temperature and velocity of the axial hot combustion gas flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial combustion gas flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is then used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir. The combustion gases then pass through an exhaust volute and to the atmosphere via an exhaust stack.

## 1.2 Project Description & Scope

The gas turbine went in service at Holyrood in 1986. As of December 2010, the unit had a total of approximately 4717 operating hours, +386,000 idle hours, and 2548 starts. Due to the age of the gas turbine and balance of plant, the large number of idle hours, and its exposure to a marine environment, it was necessary to perform a comprehensive condition assessment and life extension study. In general, the unit and balance of plant equipment requires refurbishment or replacement work to continue operating with a high degree of reliability to its required end of life of 2020. The study will identify the measures that need to be taken to ensure reliable operation of the gas turbine (GT) and balance of GT. AMEC Americas Limited (AMEC) was contracted by NL Hydro to conduct a Condition Assessment and Refurbishment/Replacement Study for the Holyrood BlackStart Gas Turbine Generator.

The scope of work consists of an engineering study that will assess the condition of the Holyrood Thermal Generating Station (HTGS) gas turbine and balance of plant and make recommendations for work including cost estimates that will be required to extend its useful life to 2020 with the same high degree of reliability as that experienced in the past. The engineering study will include a Level 2 study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three level methodology for performing condition assessment and life extension studies within the utilities industry in which the level of sophistication and detail increases progressively through Level I, Level II, and Level lll studies. AMEC shall apply this process to the gas turbine generator and balance of plant equipment.

Part A of the study is primarily a detailed condition assessment and refurbishment study of the existing gas turbine plant located at HTGS with recommendations and cost estimates to extend the life of the gas turbine plant as a highly reliable operation to the year 2020.

Some GT equipment vendors had already issued their condition reports to Hydro. Hydro made these reports available to AMEC. Following an analysis of the reports and consultation with vendors, AMEC shall make recommendations for refurbishment work necessary to extend the life of the gas turbine plant as a highly reliable operation until the year 2020. Cost estimates shall be provided for the recommendations, in addition to giving consideration to the vendor reports.

Part B of the study examines the replacement of the existing gas turbine plant with a new or good used mobile generating plant considering either:

a) A gas turbine plant consisting of two 5 MW mobile/transportable units.

b) A diesel generating plant consisting of five 2 MW diesel units.

If used generating plants are considered, they are required to be relatively new and in good condition.

The new plants are to be able to support start-up block loads up to 3 MW in a smooth and stable manner. The scope would include the decommissioning of the existing plant and removing it from site. The new units would be installed such that uninterrupted black start power availability would be provided to HTGS until new mobile installations are commissioned.

AMEC shall determine the annual operating and maintenance (O&M) cost for each of the alternatives up to the year 2020.

## 1.3 Study Basis

The basis for the study is as follows:

**In-Service:** Summer 2013

**End of Life (EOL):**

- **Holyrood Black Start:** Dec 2020 in Holyrood black start service
- **System Support:** Post 2020 for replacement options - transportable for transmission/ distribution system maintenance to various locations for further 10 to 15 years

**Operating Pattern:**

- **To 2020:** 1 start every 2 weeks to 50%+ load for two hours in winter; 1 start per month in summer; System use – 20 to 40 hrs/year
- **Post 2020:** Maximum 1 month/year operation on transmission line outage support – Maximum 720 hours per year , 6 starts/year

**Capacity Targets:** 10 MW gross peak capacity; Continuous capacity – vendor capacity based on gross peak capacity

**Energy Targets:** No specific energy production targets – Capacity and Operating Pattern define role.

**Reliability Targets:**

| | |
|---|---|
| Start Reliability: | 80% (2nd start – 96%, 3rd start – 99 %) |
| Black Start Ops Reliability: | 98% |
| Peaking Reliability: | 95% |
| Availability: | 93% (Summer maintenance) |

**Health & Safety Target**; Maximum Practically Achievable Safety

- Minimum fire risk
- Minimum catastrophic equipment failure risk

**Environmental & Regulatory Target:** Meet Newfoundland & Labrador environmental and regulatory requirements for the technology and role of the facility

## 1.4 Methodology

### 1.4.1 Part A – Existing Unit Refurbishment

GT equipment vendors previously issued their condition assessment reports to Hydro. Hydro made these reports available to AMEC. An analysis of these reports, and consultation with vendors, forms the basis for AMEC's recommendations for refurbishment work necessary to extend the life of the gas turbine plant as a highly reliable operation until the year 2020. Cost estimates were not provided by the vendors for the recommendations in their assessments. In addition to giving consideration to the vendor reports AMEC shall perform the following tasks in completing the Project.

1. Conduct Equipment Inspections – Balance of Plant (BOP)

AMEC developed a plan, including a schedule, to perform detailed inspections of the remaining gas turbine balance of plant systems and sub systems and identify refurbishment needs. Following the completion of the inspection, AMEC formulated recommendations for refurbishment work complete with cost estimates, including a schedule, that are required to extend the life of the balance of plant systems until the year 2020. The OEM's and other specialists were consulted as required to assist in the study. AMEC contacted OEM's and other specialists to provide this information to AMEC. The remaining gas turbine BOP systems and sub systems addressed by this study included the following:

1. Fuel oil system
    i. Fuel tanks
    ii. Fuel oil piping
    iii. Fuel offloading pumps
    iv. Valves
    v. Fuel supply pumps (to the gas turbine)
    vi. Strainers and filters
    vii. Fuel flow meter
    viii. Fire system trip valve
2. Electrical and controls
    i. Foxboro DCS system
    ii. DCS logic
    iii. MCC
    iv. Switchgear
    v. Governor system
    vi. Battery room
3. Compressed air system
    i. Compressor unit
    ii. Instrument air dryer
    iii. Control panel
    iv. Nitrogen back-up bottle supply
4. Building
    i. Structure
    ii. Fire protection system
    iii. Crane hoist and track system

2. Major Upgrades and Repairs

A number of major upgrades and repairs have been performed on the HTGS gas turbine and balance of plant since it went into service in 1986. AMEC reviewed available plant records pertaining to major equipment upgrades and repairs and evaluate their impact on achieving 2020 service life.

3. Determine Remaining Equipment Life

AMEC assessed the remaining lifetimes of the gas turbine plant major components and systems along with the balance of plant, consulting as required with OEM's and reviewing the historical life cycle

information for similar type facilities to assess the requirements to reach an end of life of the gas turbine plant of 2020.

4. Determine Annual Operating and Maintenance Cost

AMEC determined the annual operating and maintenance (O&M) cost for the gas turbine plant up to the year 2020, both with the recommended refurbishments and without completing the recommended refurbishment work. AMEC contacted OEM's and other specialists as required to support development of this information.

### 1.4.2 Part B – Existing Unit Replacement

AMEC developed a scope of work and cost estimate to replace the existing gas turbine plant with a new or good used mobile generating plant considering alternative arrangements as noted below. If used generating plants are considered they are required to be relatively new and in good condition.

a) A gas turbine plant consisting of two 5 MW mobile units.

b) A diesel generating plant consisting of five 2 MW mobile diesel units.

The alternative arrangements were configured such that the new plants would be able to support start-up block loads up to 3 MW in a smooth and stable manner. In addition, cost estimates included decommissioning of the existing plant and removing it from site. The alternatives considered were such that uninterrupted black start power availability would be provided to HTGS until new mobile installations are commissioned.

AMEC determined the annual operating and maintenance (O&M) cost for each of the alternatives up to the year 2020.

The study methodology included the following steps:

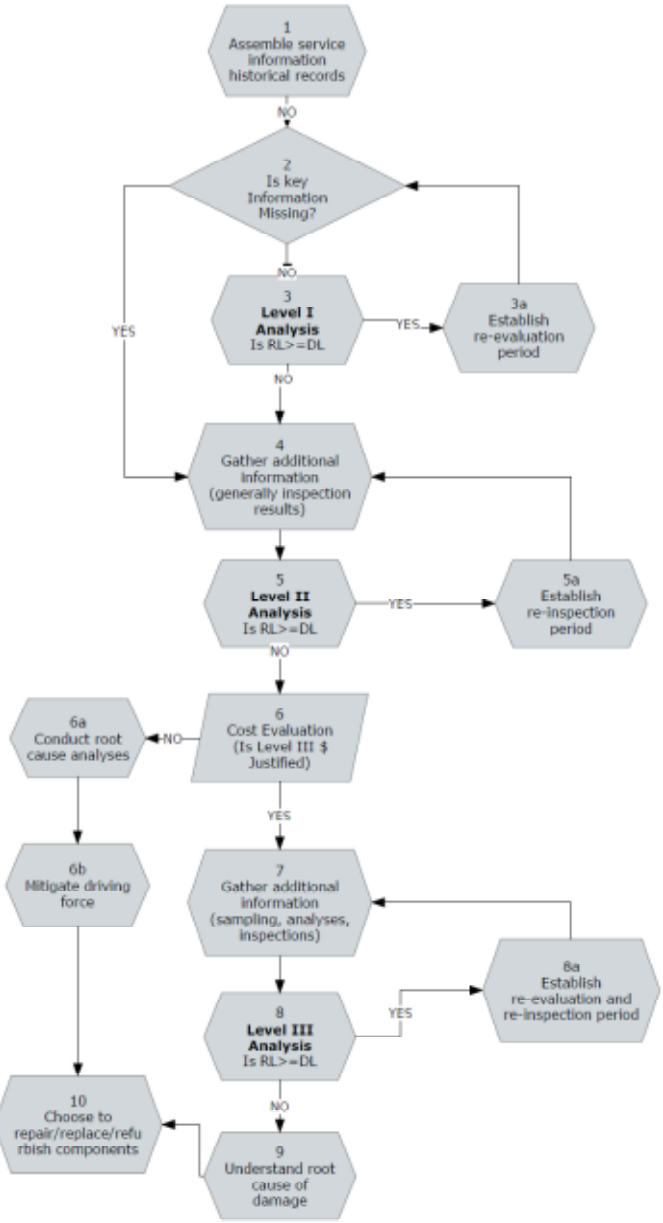
- Initial kick-off meeting and site visit
- Site review and equipment/facility inspections
- Review of the Holyrood Plant Maintenance Program – existing information/background data and staff interviews
- Review and analysis of information and data obtained through:
    2. Existing studies on condition assessment, life expectancy, previous studies of life extension, and the associated costs (capital and O & M) of such programs
    3. Previously noted physical inspection reports of equipment
    4. Equipment lost time analysis data
    5. Interviews and discussions with NL Hydro management
    6. Interviews and discussions with Holyrood Operations and Maintenance personnel
    7. Analysis of power demands vs. Holyrood generation capabilities
- Analysis of the impact and value of capital upgrades and operational and maintenance improvements
    1. Determination of remaining equipment and facility life – using existing information, experience, and OEM consultations as required to develop life cycle curves for major critical equipment and facilities not expected to exceed the 2020 end of life date; and
    2. Conduct equipment risk of failure analysis for major plant components, equipment, systems, and the entire facility which is not expected to exceed the 2020 end of life date.

3. Identify any components or systems that require further investigation; and make recommendations for work that will be required to extend the plant's useful life to 2020 with the same high degree of reliability as experienced in the past.

To the extent practical, the approach followed the intent of the EPRI Condition Assessment Level 2 process or a reasonable alternative approach as determined by individual technology experts. The basic approach consistent with the EPRI Level 2 approach is:

- Examine design or overall service parameters
- Perform Level 2 inspections (physical only, no testing)
- Compare, using conservative considerations, the expected residual life to the required 2020 service period (or the interval to the next inspection whichever is less)
- Incorporate service and measurement information where practical, available and useful including:
    1. Unit running hours
    2. Numbers of starts and stops – hot, warm, cold, trips, ramp rates
    3. Unit load records
    4. Failure history and analyses reports
    5. Maintenance activities
    6. Specifics of past component repairs and replacements
    7. Materials of construction composition checks
    8. Dimensional checks
    9. Design parameters

The generic EPRI condition assessment methodology is illustrated in Figure 1-1. This chart includes step numbers used in the report to identify where in the process various systems and equipment are considered to be.




NOTE: Remaining Life (RL) is the estimated reliable remaining life of a piece of equipment or system based on available inspection and equipment data. Desired Life (DL) is the desired life of the component, but for decision making is the earlier of the desired end of life (EOL) date or the next inspection that can yield date for life assessment purposes.

**FIGURE 1-1 GENERIC EPRI CONDITION ASSESSMENT METHODOLOGY**

For mechanical systems, it considers aspects such as:

| Feature | Level I | Level II | Level III |
|---|---|---|---|
| **Failure History** | Plant records | Plant records | Plant records |
| **Dimensions** | Design or nominal | Measured or nominal | Measured |
| **Condition** | Records or nominal | Inspection | Detailed inspection |
| **Temperature and pressure** | Design or operational | Operational or measured | Measured |
| **Stresses** | Design or operational | Simple calculation | Refined analysis |
| **Material properties** | Minimum | Minimum | Actual material |
| **Material samples required?** | No | No | Yes |

More rigorous assessment →

More accurate operation data required →

More accurate estimate of equipment RL →

**FIGURE 1-2 EPRI METHODOLOGY – INFORMATION REQUIREMENTS**

The Level 2 analysis considers several issues, such as:

- Has the unit component operation exceeded its design parameters (i.e. temperature, pressure) for significant periods of time or by significant amounts?
- Will the required future service requirement exceed significant design parameters (i.e. cycling, two-shifting capacity) without suitable modification?
- Has unit maintenance and reliability shown that the operating philosophy and materials have not been conservative since the units was operational?
- Has the failure history been excessive?

The intent in Level 2 is to address items with insufficient information to make decisions going forward. For example in the chart below, Level 1 allows selection of a number of components to replace, repair or refurbish, but leaves the majority as uncertain. Level 2 further refines the uncertain portion of Level 1.

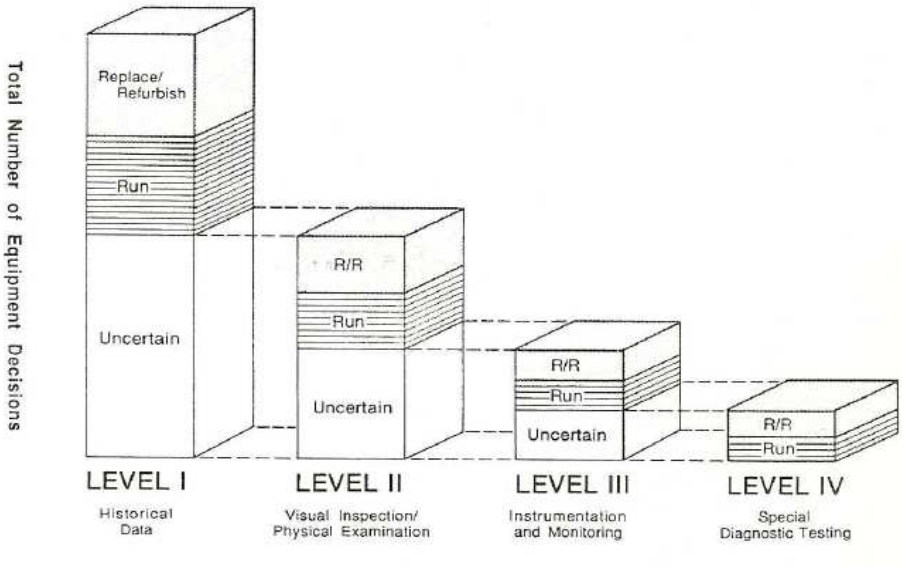



**FIGURE 1-3 FOUR-LEVEL ELECTRICAL COMPONENT LIFE ASSESSMENT**

## 1.5 Background Information and Studies

The key background information and studies included the following:

- Identification of key equipment;
- Identification of recent improvements/changes – fuel, major modifications, etc.;
- Vendor consultation;
- Current/planned station budgets and plans;
- Timing of changes – likelihood;
- Staffing, Operating, Maintenance and Administration (OMA) plans;
- Criteria for operation and operating parameters;
- Major equipment to be considered;
- Present design and operating data – e.g. temperatures, vibration data, cooling water and oil temperatures, etc. at typical load points;
- Facility drawings as required;
- Maintenance data for major pieces of equipment, especially from the last major maintenance outage. Details of known limitations, and operating concerns; and
- Details of major repairs performed on major equipment.

## 1.6 Field Investigation

It was agreed that the scope and results of field investigative work, analyses undertaken, variables examined, and operational considerations would address:

- Operating hrs and cold/warm/hot starts;
- Major outages and associated reports (planned, major maintenance);

- Major plant equipment and system changes (i.e. equipment change-out, major gas turbine modifications and generator modifications) since in-service (particularly in last 10 years) including the scope and timing of the changes;
- Major inspections (and associated reports) on key equipment and systems;
- Unit performance – capacity, heat rate, availability;
- Current budget and business plan information details; and
- Occurrences where the actual operating conditions exceeded the equipment design conditions.

## 1.7 Scope, Key Features and Parameters of Study

The study scope was discussed with NL Hydro during an initial kick-off meeting and it was agreed that:

- AMEC would adapt the Holyrood asset register as the primary index.
- The generic EPRI Condition Assessment approach illustrated in Figure 1-1 is the methodology employed. A more generic approach, using industry and individual expert experience, taking into account Holyrood specific information, was applied in many cases.
- The intent is to provide an assessment of requirements including schedule and cost. Given the stage of and eventual scope of the work, as well as the economic environment, an accuracy of +/-10-15% is a target typically achieved during detailed quotes on actual work, and the overall costs are practically speaking more of a +10/-25% quality, typical of this stage of the work.

The following key features of the study were identified:

- No new detailed information was developed. The assessment was based on existing information obtained through existing documents and studies, plant interviews, and readily undertaken visual inspections
- The findings of existing studies are taken into account.
- The intent of the EPRI Level 2 methodology is to determine whether a piece of equipment or system can either reach it's intended planned life or reach its next major inspection and overhaul. If it is indeterminable as to whether the equipment can or cannot reach its planned life or next major inspection/overall, then a Level 3 condition assessment is necessary.
- The study focuses primarily on key equipment systems required for black start operation up to 2020
- Inspection and analysis has been done by others on the major gas turbine OEM equipment as per the RFP document. AMEC will use this condition and cost information as the basis for its gas turbine assessment.
- No inspections were required for equipment identified in the Level 1 study as satisfactory – for example: fuel tanks, building siding, recent electronics equipment additions.
- EPRI Level 2 inspections were limited to equipment identified as BOP and for which visible and practical inspections are possible in AMEC's judgment.
- Inspections were only undertaken per above and only on key equipment that is not considered covered under regular OMA, but represented a life limiting issue having a probable and significant impact on the reliable operation of the unit in AMEC's judgment.
- No specific equipment testing was undertaken as a Level 2 exercise.
- Remaining life was determined and reported on for those major systems and pieces of equipment which are expected to fail before 2020 and have a significant reliability impact on the gas turbine unit in AMEC's judgment.

## 1.8 Cost Estimating and Schedule

AMEC developed cost estimates and schedule for both Part A and Part B options - to complete a GT refurbishment as well as to replace the existing gas turbine unit with either 2 x 5 MW gas turbine generators or 5 x 2 MW diesel engine generators. Where practical, the cost estimate targeted an accuracy range of +/- 10-15%. It was identified and agreed that this would not be practical in many cases given the stage of work and the labour and materials marketplace and any key considerations pertinent to completing the cost estimate and schedule provided.

## 1.9 Site Visits

AMEC staff visited Holyrood in May-June 2011:

- A one-week visit by Rupert Merer (GT expert) and Blair Seckington; and
- Various short term visits by several of AMEC St John's office staff with Civil, Structural, Electrical & Controls, and Mechanical expertise.

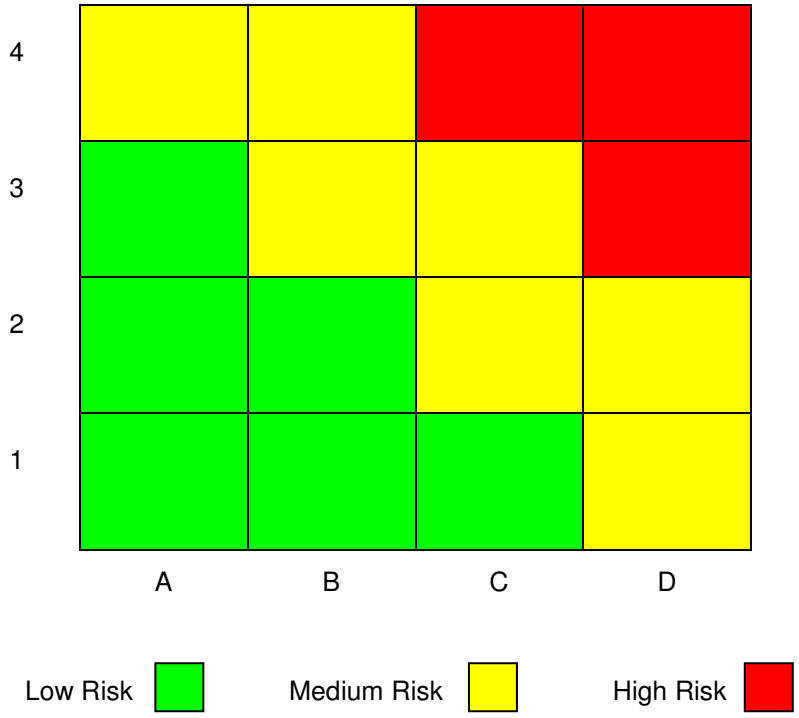
In the course of these visits, meetings and interviews included the following staff:

- Plant management team as a whole – kick-off, scope, areas of responsibility, and general information sharing;
- Terry LeDrew (Plant Manager) – key plant issues and asset history;
- Jeff Vincent (Manager-Long Term Asset Planning) – various plant asset conditions, capital plans, Instrumentation and Controls (I&C), Electrical, and organization;
- Wayne Rice (Manager-Work Execution) – various equipment and system conditions and plant staffing;
- Sean Mullowney (Plant Electrical Engineer) – various technical issues and programs regarding electrical systems, instrumentation, and controls;
- Jamie Curtis (Quality Assurance Engineer) – NDE and test program results;
- Christian Thangasamy (Plant Mechanical Engineer) – various technical issues and programs related to condensers, boilers, synchronous condenser, steam turbine generator, motors, and pumps;
- Mike Manuel (Manager-Environment, Health and Safety) – reliability;
- Alonso Pollard (Performance Specialist) – performance data (reliability and availability);
- Gerard Cochrane (Manager - Operations) – plant and equipment performance issues, plant operations issues;
- Plant Shift Supervisors and Operators (various) – plant operations issues and performance;
    - Ron MacDoanald, Willis Young
- Ron LeDrew (Emergency Response Coordinator) – Emergency Response Team (ERT) activities;

## 1.10 Technological Risk of Failure Analysis

The risk assessment model has been developed based on methods proposed by the American Petroleum Institute (API RP 580), in lieu of a model specific to the power utility industry. The basic concept consists of a 4 x 4 matrix with the consequence measured in cost terms on the base or horizontal axis and the likelihood or frequency of the event on the vertical axis. The study risk of failure analysis was performed using the model illustrated below in Table 1-1.

**TABLE 1-1 TECHNOLOGICAL RISK OF FAILURE ANALYSIS MODEL**




Likelihood of Failure Event:

1. Greater than 10 years
2. 5 to 10 years
3. 1 to 5 years
4. Immanent (< 1 year)

Consequence of Failure Event:

A. Minor ($10k-$100k or derating/1 day outage)
B. Significant ($100k-$1m or 2-14 days outage)
C. Serious ($1m-$10m or 15-30 days outage)
D. Major (>$10m or >1 month outage)

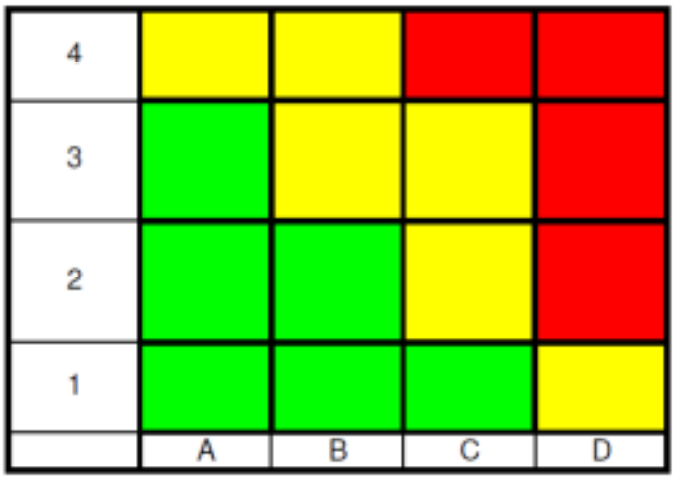
Actions:

- Items that do not apply are not ranked
- Low Risk: Monitor long term (within 5 years)
- Medium Risk: Investigate and monitor short term. Take action where beneficial
- High Risk: Corrective action required short term

### 1.10.1 Safety Risk Failure Analysis

In addition to the technological risk of failure analysis, a preliminary safety risk of failure analysis was undertaken at NL Hydro's request. Its basic format is based on that of the technological risk assessment model above and is somewhat of a hybrid of the more complex "Real Hazard Index" model used by the US Department of Defence. The modified model is presented below in Table 1-2.

**TABLE 1-2 SAFETY RISK FAILURE ANALYSIS MODEL**




Low Risk Medium Risk High Risk

Likelihood of Safety Incident Event:

1. Improbable – so that it can be assumed not to occur
2. Unlikely to occur during life of specific item/process
3. Will occur once during life of specific item/process
4. Likely to occur frequently

Consequence of Safety Incident Event:

A. Minor - will not result in injury, or illness
B. Marginal - may cause minor injury, or illness
C. Critical - may cause severe injury, or illness
D. Catastrophic - may cause death

Actions:

- Items that do not apply are not ranked;
- Low Risk: Monitor, take action where beneficial;
- Medium Risk: Investigate and monitor short term. Take action where beneficial; and
- High Risk: Unacceptable. Corrective action required short term

## 1.11 Priority Rating

A numbered priority was assigned to the various "Recommended Actions", "Level 3 Inspections", and "Capital Enhancements" of this report. The scale used was from "1" to "4". A "1" is the highest priority and essentially means that this activity should definitely be undertaken and where practical in or about the timing identified. A "4" is the lowest priority and essentially means that the item is essentially low risk and low impact and may be much more readily delayed or undertaken in some other fashion. The priority ranking is a subjective relative ranking by AMEC, meant to be an aid to Hydro in allocating resources and assessing trade-offs and program delays.

The priority ranking is not based on a rigorous process, but does take into consideration a number of aspects such as:

1. The impact (likely and worst case) of the item under consideration on achieving the end of life (EOL) goal, on plant operation health and safety, and on environmental and regulatory requirements;
2. The urgency of the need for action on the item under consideration;
3. The degree of certainty of the requirement for the item under consideration;
4. The experience at Holyrood and in the broader industry context with the item;
5. The ability to mitigate or address the issue in other ways;
6. The timing of the recommended response to the item under consideration;
7. The cost of the item under consideration relative to others; and
8. The ability of existing and planned or ongoing actions to address the item in a timely and successful manner.

The priority value of any item should be read in the context of its recommended timing. An item can be a "1", but be scheduled for a later date if it is deemed that sufficient information exists to be confident of the minimal likely impact of the deferral (usually to tie in with a planned major activity such as an overhaul).





# 2 EXISTING GAS TURBINE CONDITION ASSESSMENT

## 2.1 Gas Turbine Unit and Equipment/Processes

| | |
|---|---|
| Unit #: | GAS TURBINE |
| Asset Class # | BU 1273 Gas Turbine |
| SCI & System: | 7202 Gas Turbine System |
| Sub-Systems: | 7058 GT Power Turbine & G/B<br>7308 GT Avon Jet Engine<br>7309 GT Generator |

### 2.1.1 Description of Holyrood API Gas Turbine

The Holyrood API gas turbine is a 10/12 MW aeroderivative packaged power plant using a Rolls Royce Avon gas generator. It was designed for peaking duty to provide black start capability to the Holyrood Generating Station. The Holyrood unit is the first API produced, and had guaranteed ratings, at ISO conditions, of 12 MW peak and 8.4 MW base load. It was originally installed at Hardwoods, but moved to Holyrood in 1970. In 1986 the plant was removed from its enclosure and re-installed in a custom building with a new exhaust stack with exhaust silencer and inlet filter house.

The gas turbine generator is comprised of a number of components: inlet plenum, AVON 1533-70L power turbine, exhaust system, gearbox, generator, fuel oil system, governor/fuel control and lubricating oil system.

Ambient air enters the intake structure, passes through an intake air filter and enters the inlet air plenum. The air is compressed via a 17- stage axial flow compressor in the forward section of an AVON 1533-70L.gas generator. Fuel is supplied to an eight burner combustion section between the gas generator air compressor section and its turbine section. Combustion of the fuel results in a rapid increase in the temperature and velocity of the axial hot combustion gas flow. A three-stage turbine in the back end of the AVON 1533-70L uses a portion of the axial combustion gas flow to increase compressor rotational speed and to boost delivery. The high temperature, high velocity gas is then used to drive the power turbine and generator through a gearbox. The engine has its own on-board lubrication system complete with circulating pumps and a reservoir. The combustion gases then pass through an exhaust volute and to the atmosphere via an exhaust stack.

The whole unit was re-housed in a custom building in 1986 with new filter house, generator filters, control room and exhaust stack. New stainless steel inlet splitters were installed. A new exhaust silencer and stack were installed with exhaust hoods, a number of control upgrades have been made, and the generator compartment was provided with new filter elements.

## GTG Inlet Plenum

The inlet plenum is designed to provide approximately 140,000 cubic feet per minute of combustion air to the jet intake. This plenum is constructed of structural steel plate and framing supported by a concrete foundation. To reduce compressor damage and blade fouling, the inlet air must be free of dust and dirt.

Filtration is currently accomplished using a two stage filter. The first stage is designed for water removal, while the second was a high efficiency media type filter. It has 72 high efficiency "Farr" filter assemblies supported on tubular columns above the intake. The inlet silencer consists of acoustical splitters in a steel shell that is designed with round leading edges to create a bell-mouth entry. The trailing edges are tapered to ensure a low pressure drop and uniform flow characteristics. The plenum chamber is built from 10 cm (4 inch) thick noise-shield panels, packed with acoustic fill and secured to a rigid steel frame.

## GTG Gas Generator

The gas generator employs a Rolls-Royce AVON 1533-70L (#37029) aeroderivative gas turbine manufactured by Associated Electrical Industries (AEI) of Manchester, England. Manufacture of this type generating unit began in the mid 1960's. The unit supplied to the Newfoundland and Labrador Power Commission in 1966 was the first one off the drawing board and was considered to be a development model. The three stage turbine in the aft end of the AVON 1533-70L uses a portion of the axial air flow to increase compressor rpm and boost delivery. The high temperature, high velocity gas exits the jet through an exhaust transition duct which is used to drive the Power Turbine and thus the generator through a gearbox.

The compressor of the Rolls Royce Avon is a single shaft axial compressor unit, with a 17 stage compressor giving a pressure ratio of approximately 10 in industrial service, 8 combustors in an annular arrangement and a 3 stage turbine.

The Rolls Royce Avon gas generator is a single shaft axial unit which was developed in the late 1940s and early 1950s as a prototype axial compressor unit. It is a first generation aero engine, with no bypass. It powered a number of aircraft in the 1950s and early 1960s and very successful adapted as a gas generator, especially in gas compressor drive applications where it established new standards in the late 1960s and 1970s for overhaul life or time between overhauls. TransCanada pipelines, and other North American pipelines, standardized on the Avon until more efficient second generation units became available.

## GTG Power Turbine

The power turbine is an Associated Electric Industries Ltd. (AEI) design, manufactured in Manchester, England in early 1966. The power turbine is a single stage overhung machine designed for a normal operational speed of approximately 4900 rpm. The power turbine is connected to its generator via a gearbox and its output is converted to 1200 RPM in a vertical pinion and wheel gearbox (ratio of 4:1). The power turbine and gearbox are mounted on the centre section of the unit bedplate with this section also forming the main lubricating oil tank. Auxiliary and emergency oil pumps are mounted on this same base plate. The power turbine casings (volute) were replaced in 1986.

The power turbine uses heavy duty steam turbine construction techniques in contrast to the Avon. The power turbine shaft and disk are solid, although the inner cylinder which constrains the gas flow is fabricated from nimonic materials (nickel based alloys with high temperature tolerance). The power turbine disk is a low alloy ferritic material and it is probable that it has an operating limit of about 535 Deg C. It is cooled by a mixture of bleed air from the Avon and outside air. The power turbine diaphragm and moving blades are nimonic. The power turbine blading is nimonic and uses axially serrated roots, which are now common on modern gas turbines but were only used by AEI in the 1960s for highly stressed locations.

## GTG Gearbox

The main gearbox was manufactured by AEI in Manchester, England. It is designed to provide an approximate 4:1 speed ratio from the power turbine shaft to the main generator shaft. The power turbine operates at about 4800 RPM and its output is converted to 1200 RPM in a vertical pinion and wheel gearbox. AEI had built quite complex marine and other gearboxes and the API unit was well within their experience. The gear train is fitted to the power turbine rotor by semi-flexible coupling housed within the gearbox. The gears are of the single helical, single reduction type with the pinion mounted directly above the wheel. A removable top cover allows for inspection without disturbing the alignments.

## GTG Exhaust System

The exhaust casing (volute) is a welded fabrication divided along the horizontal centreline. It turns the combustion gasses transversely to the machine and vertically upwards to the exhaust silencer.

The exhaust stack is constructed of heavy gauge steel plate with light gauge steel cladding on the exterior. The exterior cladding of the lower half of the exhaust stack is constructed of heavy gauge steel plate. This stack was replaced during the 1986 major upgrade. The snow doors on the exhaust stacks are pneumatically actuated and were a new addition in 1986 to reduce corrosion of the volute and power turbine from infiltration of snow and rain water which promoted corrosion within the unit. New limit switches installed on the doors in 2009 indicate the position (opened or closed) of each door at the control station.



**FIGURE 2-1 GTG GAS ENGINE & GENERATOR**

## Generator

The generator is an air-cooled, 14 MW, 13.8 kV, 3 phase, Type AG 80/100, built by Associated Electric Industries (AEI) of Rugby, England in 1966. It has a rotating-field, salient-pole tube with 6 poles and rotates at 1200 rpm. The brushless exciter eliminates the danger of contamination by carbon dust and minimizes maintenance. Semi-conductor rectifiers rotating within the generator/exciter shaft provide excitation for the main generator field.

**Governor and Fuel Control**

The standard Avon fuel control system is used without alteration as a basis for the API governing and fuel control system. The throttle valve is used as a generator valve and the H.P. cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply. Woodward Governor suggests that the present system has a reliability of about 50%. In addition, spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

**Excitation System**

The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-1 3. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a "Normal" and "Standby" automatic voltage regulator (AVR) backed up by a "Manual" control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

### 2.1.2 Operating History

| | |
|---|---|
| Original Manufactured/Delivered | 1966 |
| In-Service Date at Hydro | 1970 |
| Rehoused at Holyrood | 1986 |
| End of Planned Life Date | 2020 |
| Last Combustion System Inspection/Overhaul | 2009 |
| Next Major Overhaul/Inspection/Refurbish/Replace | 2012/13 (Recommended) |

The gas turbine generator system at the plant serves as a black start unit for the station. It is occasionally used for system support as well. The hours associated with the unit are provided in Table 2-1 below.

To date, the gas turbine has operated for 4770 hours and 2548 starts. The numbers of hours operated during different phases are shown in the table, below.

**TABLE 2-1 HOLYROOD API OPERATING HISTORY**

| | Hours | Starts | Hours/yr | Starts/yr | Starts/hr | Idle/hr |
|---|---|---|---|---|---|---|
| 1966-1978 | 1749 | 611 | 140 | 47 | 3.0 | 85,000 |
| 1979-1985 | 390 | 185 | 65 | 32 | 2.0 | 85,000 |
| 1986-1995 | 1336 | 644 | 134 | 64 | 2.0 | 85,000 |
| 1996-2005 | 332 | 585 | 33 | 59 | 0.5 | 85,000 |
| 2006-2011 | 961 | 523 | 174 | 87 | 0.5 | 51,600 |
| TOTALS | 4770 | 2548 | | | | 391,600 |

Peaking units traditionally operate for between 500-1000 hours per year, but the Holyrood API has averaged closer to 100 hours per year, and many of these hours, at least in recent years, have come from monthly test runs.

Some parts have been refurbished or replaced. The pattern used for the hours of operation and starts to the end of life date of 2020 is:

**TABLE 2-2 HISTORICAL AND FORECAST OPERATING PATTERN**

| | Year To Dec 31 | GT Ops Hrs | | GT Idle Hrs | | GT Starts | | GT Ops Hrs/Yr | | GT Starts/Yr | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Low | High | Low | High | Low | High | Low | High | Low | High |
| Balance of Plant | 1966 | 0 | | 0 | | 0 | | | | | |
| | 1978 | 1749 | | 85000 | | 611 | | 139.9 | | 48.9 | |
| | 1985 | 2139 | | 170000 | | 796 | | 55.7 | | 26.4 | |
| | 1995 | 3475 | | 256000 | | 1440 | | 133.6 | | 64.4 | |
| | 2005 | 3807 | | 343000 | | 2025 | | 33.2 | | 58.5 | |
| | 2010 | 4717 | | 386000 | | 2548 | | 182.0 | | 104.6 | |
| | 2011 | 4737 | 4737 | 394740 | 394740 | 2558 | 2563 | 20 | 20 | 10 | 15 |
| | 2012 | 4737 | 4737 | 403500 | 403500 | 2558 | 2563 | 0 | 0 | 0 | 0 |
| | 2013 | 4809 | 4887 | 412188 | 412110 | 2585 | 2635 | 72 | 150 | 27 | 72 |
| | 2014 | 4881 | 5037 | 420876 | 420720 | 2612 | 2707 | 72 | 150 | 27 | 72 |
| | 2015 | 4953 | 5187 | 429564 | 429330 | 2639 | 2779 | 72 | 150 | 27 | 72 |
| | 2016 | 5025 | 5337 | 438252 | 437940 | 2666 | 2851 | 72 | 150 | 27 | 72 |
| | 2017 | 5097 | 5487 | 446940 | 446550 | 2693 | 2923 | 72 | 150 | 27 | 72 |
| | 2018 | 5169 | 5637 | 455628 | 455160 | 2720 | 2995 | 72 | 150 | 27 | 72 |
| | 2019 | 5241 | 5787 | 464316 | 463770 | 2747 | 3067 | 72 | 150 | 27 | 72 |
| | 2020 | 5313 | 5937 | 473004 | 472380 | 2774 | 3139 | 72 | 150 | 27 | 72 |
| | | | | | | | | | | | |
| Combustor: | 2020 | 713 | 1337 | | | 1174 | 1539 | 72 | 150 | 27 | 72 |
| PT Volute: | 2020 | 2213 | 3837 | | | 1974 | 2339 | 72 | 150 | 27 | 72 |

The unit has operated for an average of about 100 hours per year and about 50 starts per year, consistent with use for emergency peaking. Although distillate fuel is used resulting in high unit energy costs, little attention has been given to efficiency due to the peaking/emergency roles of the unit. The station operators have demonstrated that they can usually start the unit fairly quickly, although it often takes several attempts. The station does not record starting reliability, which is one of the most important criteria for a normal peaking emergency unit.

One interesting aspect for early Avon units without corrosion protection was that each standby hour may have consumed the equivalent of 0.3 hours of running life. (Maintenance and Support of Mature Gas Turbines – M. Hudson, Siemens 2005)

### 2.1.3 Major Maintenance History

The API unit was originally supplied in its own packaging, but in 1986 the unit was relocated into a custom building with a new inlet filter house and exhaust stack. At that time a GEM80 PLC was installed.

The unit has had significant overhauls/repairs in 1978, 1986, 1991, and 2007.

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine since 1991. No details of the overhaul work in 1991 (or prior) were available for this study. Limited data on the maintenance of the unit before 1986 was available, with the exception of the Avon.

**16 October 2003**

- Annual boroscope inspection;
- Slight erosion on casing. Re-protect next shop visit;
- Normal amount of carbon build up on nozzle heads;
- Boroscope inspection satisfactory; and
- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

**10 August 2004**

- Annual hot section inspection & failure to start;
- Housing found to have corrosion on struts, will require protective coating next shop visit;
- Air plenum cleaner than last visit, holes still visible in walls;
- Compressor rotor and stator vane blades in dirty condition;
- Normal amount of carbon build up on nozzle heads;
- Slight damage to #7 Combustion Can; and
- Starting motor replaced, due to seizure. (Solved starting issue).

**27 September 2005**

- Annual inspection and boroscope inspection;
- Front Bearing Housing, outer bushes loose;
- Front Bearing Housing, Corrosion/ pitting;
- Corrosion/ Rust found in Plenum;
- HP NGV's have slight erosion of the leading edges and minor cracks in the trailing edges;
- Flame tubes have minor erosion on some of the wiggle strips and some carbon build up within the flame tube, especially around the dish where liquid fuel has collected;
- Normal amount of carbon build up on nozzle heads; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

**13 March 2006**

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

**13 April 2006**

- Fuel oil leak on underside of gas turbine at IGV Ram, seal deterioration.

**25 May 2007**

- AVON repair and boroscope inspection: IGV ram leak, ignitor failure, hot air leak from #6 burner, bellmouth nuts loose, combustion casing boroscope port bolts loose, bleed valve ducting broken and separated, fuel lag at idle and struggling at speed;
- Significant sparking coming from PT splash plate (rubbing shaft). Suggests bearings are worn and thus damaged seal;
- 2 IGV bushes replaced due to wear in the bush. (Majority of bushes and retaining nuts were replaced as well as the locking bush);
- Rebuild of the intake with securing bolts torque and locked;
- IGV ram replaced due to leak;
- Fuel filter replaced due to feed issues;
- Bolts holding PT seal were not tight, seal incorrectly installed;
- Ignitor, lead and box were replaced;
- High fuel consumption noticed at fuel drain valve, suspect worn seals on FCU and fuel pumps;
- Additional breather recommended for rear of gearbox unit, to reduce leaks;
- Compressor section; front bearing housing, inlet guide vanes have significant corrosion and coating loss;
- Combustion cans show signs of cracking, material loss (could lead to further turbine damage);
- IP nozzle guide vanes and HP nozzle guide vanes show signs of cracking on trailing edges;
- Change PT lube oil filters; and
- Replace/ Repair exhaust snow doors.

**21 May 2008**

- Package filtration inspection;
- Plenum survey;
- Windmill inspection of compressor;
- Boroscope of compressor and VIGV;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables);
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades;
- Boroscope inspection: rear of compressor, snout area, combustion can, HP nozzle guide vanes, cooper beams (crooks washers), turbine section;
- PT and gearbox review; and
- Controls review.

**10 June 2008**

- Water pooling noted in intake plenum along with holes in structure and loose debris;
- Compressor showing significant corrosion and pitting on front bearing housing, inlet guide vanes and compressor stages, physical signs of salt evident;
- Combustion cans need to be replaced due to extensive corrosion, #1 and #2 burners removed for inspection. Seized bolts prevented removal of others;

- Hard impact damage evident in turbine stages, suspect debris from combustion cans and/or intake plenum;
- Suggested unit overhaul for blade recoating etc.; and
- Fuel pump and FCU to be repaired.

**15 October 2009**

- Engine removed and placed on site, in vertical stand for repairs (combustion cans);
- Combustion cans were replaced and FCU and fuel pump repaired;
- Loose discharge nozzles, due to broken brackets (2 off) to be replaced in future;
- PT inspection showed signs of light blade rub, none on stators. Diaphragm free of damage;
- PT inlet cone cranks, to be repaired;
- Thermocouple damage, quick fixed. To be upgraded;
- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

**20 November 2009**

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to; low fuel pressure, low oil pressure, incomplete start sequence; determined igniter box malfunction, N2 probe incorrectly connected & FCU actuator tuning;
- Exhaust transition lagging replaced due to fuel saturation;
- Split air manifold cracks, to be repaired; and
- Suggest monitoring setup for the 8 EGT thermocouples.

**2011**

In the years 2010 and 2011, NL Hydro undertook a number of activities with vendors that have the Original Equipment Manufacturer (OEM) rights to the gas turbine sections in order to conduct internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates.

1. Rolls Wood Group (OEM rights to the Avon gas generator) in 2011 conducted detailed internal inspections of the front end bearing assembly, compressor rotor, compressor casings, combustion assembly, nozzle casing, rear bearing housing, turbine assembly, exhaust unit, and accessory equipment and have prepared a field inspection report. Some refurbishment estimates were provided separately.
2. Greenray Turbines (Lincoln) Limited (OEM rights to the power turbine and gearbox) in 2011 performed detailed internal inspections of the power turbine and the gearbox gears, bearings, and seals.
3. Siemens (OEM rights to 14.150 MW generator including the direct couple cooling fan, the 73.5 KW brushless AC exciter, the AC lube oil pump motor, the DC back-up lube pump motor, and the 25 HP outside fuel off loading pump motor) performed detailed internal inspections and testing of the above noted equipment.

4. Braden Manufacturing is a company that specializes in the design and manufacturing of combustion turbine air filtration systems, air inlet systems, and exhaust systems. They were recently contracted by NL Hydro to perform detailed inspections of the gas turbine air inlet plenum, air filtration system, air inlet plenum support structure, exhaust stack and exhaust stack support structure.

**GTG Inlet Plenum**

When the API gas turbine was constructed, there was little experience of packaging units of this size and the API package was not adequate for the tough marine duty that the unit experienced. The inlet filters, exhaust silencer, exhaust stack and other components corroded quite rapidly and were all replaced in 20 years or less. The original inlet filters were the inertial type which was fairly standard at the time and were still the standard type of filter on TransCanada Pipeline (TCPL) units until the early 1970s. Inertial filters gave good performance in inland locations and places where the dust loading was not excessive. They were not completely satisfactory in icing conditions as the by-pass doors sometimes opened on overpressure, and TCPL suffered a number of cases of ice damage to Avon units. Inertial filters are not capable of handling a high salt content in the inlet air. The original stack had an internal liner which corroded rapidly and did not protect the outer layer against high temperatures. We have limited information on the original silencer splitters but the exhaust unit appears to have corroded very rapidly. We assume that it was not constructed from stainless steel.

The whole unit was re-housed in a custom building in 1986 with new filter house, generator filters, control room and exhaust stack. A new Farr filter building was purchased using a two stage filter- the first stage being designed for water removal while the second was a high efficiency media type filter. This filter was probably quite efficient when new, but with modern experience of high salt environments, largely gained from marine gas turbines, it is clear that its design was not adequate for a location within 200 ft of the ocean, where strong winds are common. Such a location would now require a 3 stage filter with one stage specifically designed for the removal of saline droplets. It is clear that the performance of the filter has deteriorated through time, and in recent years there has been increased evidence of salt ingestion in the Avon. The filter now has air gaps between the filter elements, due to rusting.

New stainless steel inlet splitters were installed and appear to have suffered little deterioration in the subsequent 25 years. A new exhaust silencer and stack were installed with exhaust hoods, and the stack has been severely corroded for a number of years. At the time a number of control upgrades were made, and the generator compartment was provided with new filter elements.

**GTG Gas Generator - Avon**

The early Avons were designed to have a Time Between Overhaul (TBO) of 1500 hours in peaking mode, and 8000 hours or more at base load. Later units achieved much higher base load overhaul intervals, but with some component upgrades. These overhaul intervals probably don't apply for a unit operating for fewer than 200 hours per year, but there is no established criteria for adjusting TBO for long periods of inactivity.

In any case the overhaul life of the Holyrood unit is much more influenced by the high salt atmosphere in which it operates, and the quality of inlet filtration. If the unit had operated entirely at base load in a clean environment, it would probably not require a hot end overhaul or the replacement of any hot end parts in less than 8000 hours.

Between 1966 and 1991, NL Hydro regularly sent the Avon unit to Rolls Royce Canada or other overhaul facilities, at significant expense.

The Avon was overhauled on the dates shown in Table 2-3 below.

**TABLE 2-3 HISTORY OF AVON OVERHAULS**

| Year | Overhaul By | Overhaul Scope |
|---|---|---|
| 1978 | Not Available | Comp #7,8 replaced Titanium. Compressor recoated. |
| 1986 | Not Available | Overhaul |
| 1991 | GTC Scotland | Overhaul |
| 1993 | RR Canada | Hot End inspection |
| 1997 | RR Canada | Hot End inspection |
| 1998 | RR Canada | Inspection; replace IGV rams |
| 1999 | Onsite TCT | Boroscope and report. Minor work |
| 2001 | Onsite TCT | Boroscope and report. Minor work |
| 2002 | Onsite TCT | Boroscope and report. Minor work |
| 2003 | Onsite TCT | Boroscope and report. Minor work |
| 2004 | Onsite TCT | Boroscope and report. Minor work |
| 2005 | Onsite TCT | Boroscope and report. Minor work |
| 2007 | Onsite Alba | Boroscope and report. Minor work |
| 2008 | Onsite Alba | Boroscope and report. Minor work |
| 2009 | Onsite Alba | Replaced combustor cans. |

The Avon has been inspected at regular intervals, as shown in Table 2-3. It has not been shipped to Rolls Royce or an OEM since 1991.

Since 1991, Hydro has arranged for a boroscope inspection at regular intervals, but the unit has not left the site. On each of the six inspections between 1999 and 2006, the inspection report stated that the unit appeared to be in satisfactory condition. A number of minor repairs have been made since 1991. They included replacement of inlet guide vanes (IGV) bushings and IGV rams, tightening of nuts and replacement of minor components but no major gas path component was replaced until 2009, when the combustor cans were replaced.

In recent years, the Avon has generally operated reliably. However, there is evidence of accelerated corrosion and pitting resulting from deterioration of the inlet filter. The filter is badly corroded and is now allowing unfiltered air to enter the plenum and the engine.

**GTG Power Turbine**

No major maintenance has been done on the power turbine since 1986. Access to the rotor and disk is difficult and until 2010, the only boroscope inspections which were done were performed from the front.

This allowed reasonable inspections of the inlet cones and the diaphragm ring, but not the rear of the turbine disk or the blade roots. In 2010, Greenway obtained a very limited boroscope picture of the power turbine blade roots. We have seen no record of any earlier inspection of the rotor, disk, blade roots or the whole of the moving blades.

**GTG Gear Box**

As early as 1970, the AEI engineers supervising the move of the unit to Holyrood noted several problems with the gearbox. These problems included leakage from the drive end bearing cover on the high speed pinion,) leakage from the generator end low speed shaft, and inadequate gearbox venting. The first of these problems was resolved by machining a groove in the cover plate and inserting an 'O' ring. The second issue was subjected to various adjustments and minor modifications so that the leakage was reduced to an acceptable level. The AEI Engineer's notes refer to components ordered from the factory to further reduce leakage, but the correspondence doesn't indicate what changes were made, and whether the new materials were ever fitted.

We do not have written records of any other gearbox leakage before 2005, but verbal discussions with operators suggest that it has been a growing problem for at least 20 years, and possibly longer. Some time before 2007, it was thought that gearbox oil pooling under the exhaust volute had caused a fire. However, when Alba Power inspected the unit later that year, it was noted that the fire had been the result of leaking fuel oil from failed start attempts on the Avon.

In March 2010, there was a fire under the exhaust stack, and the events following this fire are fully documented in NL Hydro's "Sequence of Events Report" which is included in Appendix 2. The fire caused justifiable safety concern with the operators, and it was reported to the Provincial Department of Occupational Health and Safety, who imposed an operating restriction on the unit.

Alba Power was asked to review and repair the lube oil system and a number of oil leaks were eliminated or reduced:

- Leaks in the auxiliary lube oil piping around the AC, DC and shaft driven pumps were re-gasketed, with the leakage eliminated.
- A new set of seals were manufactured for the generator end of the power turbine gearbox and a large temporary containment dish was installed under this leaking seal. This reduced leakage to what Alba described as "an acceptable level"
- Oil was weeping from the top of the power turbine casing, an instrumentation line and the aux trip bolt mechanism. Repairs eliminated these leaks

After 12 hours of operation at 10 MW, smoke was still seen coming from the top of the gas turbine gearbox in the vicinity of the stack. NL Hydro staff assumed that the seal on the front of the high speed gearbox shaft was also leaking. While a prudent assumption, it is possible that any front end leakage may actually come from another location. The unit has not operated since.

The only conclusions which could be drawn from AMEC's site visit, when the unit was not operating and was fully assembled, were:

- The only visible evidence of fire is a relatively small black charred area above the gearbox on the exhaust volute.
- The existing fire detection equipment is inadequate and did not detect the 2010 fire.
- No ignition source has yet been determined.
- While the new Inergen fire suppression system is safe for operators, it may not be capable of extinguishing an oil fire in the GT compartment, as presently configured, because of the large flow of ventilation air in the compartment. Given that the compartment should be unmanned

during operation, the fire detection and suppression systems should be capable of detecting and controlling fires without the entry of Hydro operating personnel. The overall fire detection and fire protection status of the unit should be reviewed in detail.

At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). There is some evidence to support two of the leakage mechanisms, which may compound each other. The principal causes which have been proposed are:

1. The seal between the power turbine shaft and the front bearing support structure (which is an extension of the gearbox casing) is a double labyrinth which is sealed in the middle by air taken from an Avon compressor bleed. Alba noted, in their May 2007 report, that the pressure in the gearbox (measured by a gauge mounted on the gearboxes casing) rises with load and have suggested that the gearbox is being pressurized by the Avon bleed air. At a load of 10 MW the pressure in the gearbox was 3 inches water gauge. Alba tried to resolve this by adding another oil tank vent, which appeared to reduce the leakage.

   This problem has occurred on other gas turbines and one of the upgrade options offered by GE for their Frame 5 and 6 units, with outputs of 17.5 MW to 40 MW, is to install an oil tank vent blower with coalescer, which maintains a small vacuum in the gearbox and coalesces the oil taken from the tank and returns it via a drain.

2. The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008, Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.
3. Misalignment has been proposed as a cause of the leakage, but there is no direct evidence of this.
4. The rear labyrinth seal appears, from the limited data available to us, to be too short. An ideal labyrinth seal should have at least 3 labyrinth sections with oil drains between the sections. The existing seal seems to have only two sections with no oil drain.

**Generator and Exciter**

The Generator, Exciter, AVR and controls were standard at the time of their installation. There has been no major maintenance on the generator or the exciter since 1986. NL Hydro established a draft maintenance procedure in 2009, which included performing insulation integrity tests every second year on both the generator and exciter (resistance to ground, polarization, and resistance phase to phase). The trends of these readings can mean as much as the absolute values, but no figures for them were available before the Siemens tests of 2011.

### 2.1.4 Condition Assessment & Remaining Life

**GTG Gas Generator**

It is now industry practice to specify the overhaul life of a gas turbine in terms of “Hot end overhauls”, during which the high temperature components such as the combustors and turbine blading are refurbished or replaced and “Major maintenance overhauls”, where the hot end and other components are repaired or replaced. The most expensive element of gas turbine maintenance is normally the replacement of high temperature components, and on newer machines this represents up to half of the total cost of a major overhaul. Many high temperature components may have an expected life between refurbishment of over 20,000 hours but can be refurbished one or more times.

The Avon overhaul life was originally established as 1500 hours in peaking mode and up to 8000 hours at base load. With experience, these figures were increased to 4000/5000 for peak load and 25,000/30,000 for base load.

Rolls Royce (RR) now does not directly support older Avon units but there are a number of experienced companies providing support. These companies do not generally differentiate between “Hot end” and “Major” overhauls but offer “Standard overhauls”. It is expected that all of the parts of Avon can be replaced because parts for the Mk-1533 Avon units are plentiful and generally inexpensive. Avon turbine blading has relatively simple metallurgy and cooling arrangements, so it is inexpensive compared to the blading of newer gas turbines.

It is difficult to determine how much of its overhaul life the Avon has expended. All of the recent boroscope reports suggest that it is in reasonable condition, but none of the turbine components have been replaced in the last 20 years, according to our records, and the HP turbine blading and IP vanes have not been replaced or refurbished for over 25 years .

The unit was examined by Rolls-Woods in Nov 2010 and Alba power in 2009 and a summary of their findings is provided below:

- Rolls Woods state that generally the engine appears to be in reasonably good and serviceable condition. The compressor stator components, compressor stators, bleed valves and outer casing were all in reasonably good condition, with most components showing some loss of coating and light corrosion. Components that have deteriorated in the past, such as the front bearing housing and IGV bushings appear to be in good condition. Hot end components also appear to be in good condition with minimal visible damage.
- Alba report that the Avon is in good condition, but are concerned about the loss of coatings, especially on the compressor. It is their opinion that further loss of coating may damage components to the point that they cannot be refurbished.

Normally, the overhaul life of a peaking unit is influenced most by high temperature fatigue while a base load unit is normally limited more by creep, oxidation and corrosion. Boroscope inspections give only limited data on fatigue and creep life expenditure. It is possible that the unit may have operated at its Peak output, earlier in its history, as there are signs of overheating in some of the generator coils (although these could be the result of phase imbalances). Because the engine is rarely washed and has extensive corrosion and pitting, it is likely to have suffered significant performance degradation, which might have reduced its output by up to 10%. (some early US navy gas turbines suffered up to 15% output degradation). The base load output of a degraded unit at high ambient temperatures, would be below 8 MW and the operators may unwittingly have operated at peak, at some time in the unit’s 45 year history.

Our estimate of the Avon’s equivalent operating hours is shown in Table 2-4, below.

The time between overhauls for the existing Avon unit, which are nominally 8,000 hours at peak load and 25,000/30,000 at base load, have to be adjusted for 5 factors, discussed below:

- Between 30 and 40 years ago, Rolls Royce introduced a starts factor making each start equivalent to 10 hours of operation. This factor is somewhat subjective. Most large modern aeroderivative units do not have such a factor, and the manufacturers claim that the number of starts has little effect on overhaul life, if starts are limited to a reasonable number. RR’s current guidance on the Avon is that the equivalence factor is dependent on the type of fuel and the ratio of hours per start. Given that the Holyrood machine burns liquid fuel and has an operating hours to starts ratio of below 3, each start should be counted as ten hours of base load maintenance life.

- The unit operates in a very high salt environment and during the first 19 years of its operating life, and the last five or more years, it has had inadequate inlet filtration. This has affected the compressor blading and casing more than the turbine. There has been a significant loss of compressor coatings.
- The unit operates for very few hours per year. There is little data on how this influences maintenance life, but at Holyrood it seems to have had little effect.
- The unit burns distillate which reduces maintenance life when compared to natural gas.
- The Avon is a very early unit, without many of the later modifications introduced to increase overhaul life.

**TABLE 2-4 CALCULATION OF EQUIVALENT OPERATING HOURS**

| | Equivalent operating hours since 1991 | Total equivalent operating hours |
|---|---|---|
| Components affected | HP vanes, IP turbine blading, misc other | Many components have never been refurbished |
| Operating hours | 2,000 approx | 4,700 |
| Hours equivalent of starts @ 10 hrs per start | 14,000 | 25,000 |
| Discount for oil fuel. Typically 25% adder on other gas turbine types | 4,000 | 7,425 |
| Discount for corrosion | See note below | See note below |
| Approximate totals | 20,000 plus | 38,000 plus |

*Note on Corrosion: Corrosion appears to have affected the compressor blading and casing more than the turbine. Given that compressor components should have a longer operating life than the turbine, corrosion may not be the key factor in determining overhaul life. Also salt appears to have affected the coatings on the compressor more than those of the turbine . The former are designed to protect the blades, while turbine coatings reduce heat flux and protect the rotor and disk from excessive temperatures. We note that the turbine rotor was replaced before 1986.*

The data which is available to AMEC suggests that most of the turbine components are original, with the exception of HP nozzle blades and IP turbine blades. On the Avon the turbine nozzles usually suffer more deterioration than the moving blades. Table 2-4 suggests that, as a minimum, the HP turbine blading and IP nozzles may require refurbishment.

There are many other components on the Avon which cannot be seen during a boroscope inspection, so their condition is unknown.

The Avon requires an overhaul to replace coatings and repair or replace turbine blading and other components which have suffered cracking or other damage. It is expected that when the Avon has been overhauled and the inlet filters replaced, it will not require a further significant overhaul before life end in 2020. In addition, the future annual maintenance costs would be less than $10,000 per year.

**Power Turbine**

The power turbine has received little attention since 1986. A boroscope photograph from 2011 is the only one that we have seen that shows the power turbine blading roots. This shows only a small number of blade roots but the disk material in the axially serrated root appears to be severely corroded. The photos do not show the bulk of the disk itself so we have no way of knowing if this corrosion is present on the

remainder of the disk, and whether it is superficial or deep. In the photo, it appears to extend under the root. Steam turbines can suffer from blade root corrosion caused by materials collecting in the root, and it is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively, the whole disk may be corroded. In either case, the roots are very vulnerable to stress corrosion cracking.

It should be noted that the turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading.

The Power turbine disk material is a low alloy ferritic steel selected for its high transition temperature. It seems likely that such a material has a service limit of 535 C or lower. The Avon exhaust cone temp (ECT) is close to 640 deg C at the full peak rating, so clearly the design of the API depends on effective disk and blade root cooling. It is probable that the blade root is highly stressed at full load, even with its design cooling. The axially serrated root was the most expensive blade root used by AEI, and so they only used it for highly stressed locations.

Greenray, who now legally represent AEI gas turbines and hold all rights to their technology, do not think that the power turbine should be operated in its present condition, and AMEC agrees with this recommendation.

Based on the information available to AMEC, it appears that the turbine disk should be replaced, using most or all of the existing moving blades. Welding repairs are required on the inlet cones, struts, heat shield, etc and can be used for slightly damaged blades. The cooling air system should be examined carefully as it is essential for the integrity of the power turbine disk and blading. With these measures, there should be no problem operating the power turbine for another ten years or more. The highest risk is the loss of a diaphragm or moving blade.

**Gearbox**

The gearbox pinion and wheel were examined briefly by Alba in 2007 and appeared to be in good condition at that time. A gearbox of this type should operate for many years without problem, and if the bearings and seals are replaced, the gearbox should not present a large risk. The cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft must be determined and rectified. Although the high speed gearbox shaft has more complex labyrinth seals than those of the generator end, and an air seal, it is probably prudent to assume that this seal is also leaking.

The only conclusions which could be drawn from AMEC's site visit, when the unit was not operating and was fully assembled, were:

- The only visible evidence of fire is a relatively small black charred area above the gearbox on the exhaust volute.
- The existing fire detection equipment is inadequate and did not detect the 2010 fire.
- No ignition source has yet been located.

- While the new Inergen fire suppression system is safe for the operators, it is important to confirm that it is capable of extinguishing an oil fire in the GT compartment, as presently configured, and with all ventilation is shut off in the event of a fire. Given that the compartment should be unmanned during operation, the fire detection and suppression systems should be capable of detecting and controlling fires without the entry of Hydro operating personnel. The overall fire detection and fire protection status of the unit requires a detailed review.

At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). There is some evidence to support two of the leakage mechanisms, which may complement each other. The principal causes which have been proposed are:

a. The seal between the power turbine shaft and the front bearing support structure (which is an extension of the gearbox casing) is a double labyrinth which is sealed in the middle by air taken from an Avon compressor bleed. Alba noted, in their May 2007 report, that the pressure in the gearbox (measured by a gauge mounted on the gearboxes casing) rises with load and they suggested that the gearbox is being pressurized by the Avon bleed air. At a load of 10 MW the pressure in the gearbox was 3 inches water gauge. Alba tried to resolve this by adding another oil tank vent, which appeared to reduce the leakage.

   This problem has occurred on other gas turbines and one of the upgrade options offered by GE for their Frame 5 and 6 units, with outputs of 17.5 MW to 40 MW, is to install an oil tank vent blower with coalescer, which maintains a small vacuum in the gearbox and coalesces the oil taken from the tank and returns it via a drain.

b. The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008, Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.
c. Misalignment has been proposed as a cause of the leakage, but there is no direct evidence of this. Another GE upgrade on older gas turbine models is an improved flexible coupling between gas turbine and the load gear.
d. The rear labyrinth seal appears, from the limited data available to us, to be too short. An ideal labyrinth seal should have at least 3 labyrinth sections with oil drains between the sections. The existing seal seems to have only two sections with no oil drain.

Both Alba Power and Greenray, have quoted for the repair of the gearbox, and the bids of both of these companies suggest that the problem can be resolved by restoring the unit to its original design, with better venting. The adequacy of this proposed repair is reinforced by the fact that the Newfoundland Power Commission API unit at Salt Pond has not suffered from oil leaks, and that both Alba and Greenray have experience of other API units.

Since 1991, NL Hydro has arranged for a boroscope inspection at regular intervals, but the unit has not left the site. On each of the six inspections between 1999 and 2006, the inspection reports indicated that the unit appeared satisfactory. A number of minor repairs have been made since 1991, including replacement of IGV bushings and IGV rams, tightening of nuts, and replacement of minor components. However, no major gas path component was replaced until 2009, when the combustor cans were replaced.

**GTG Inlet Plenum**

It is clear that in the high saline atmosphere at Holyrood, operating with an increasingly ineffective inlet filter, the unit has suffered considerable degradation during very few hours of operation. For example,

Alba Power reported that between May 2007 and June 2008, the unit had only ran 26 hours with 54 starts and there was considerable degradation of the combustors and other components, which may have corresponded to less than one month of operation in a normal base load unit. The unit is rarely washed because washing is normally performed largely to maintain efficiency. However, it would be beneficial to wash the Holyrood unit because of the buildup of salt on the first stages of the compressor. At present, the engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. There is also cracking in the turbine section.

Without replacement, the Avon and PT will degrade rapidly. The inlet air filter/media should be replaced and/or brought back to reasonable condition.

**Generator**

Siemens inspected the generator in 2011 and performed (resistance to ground tests (megger), polarization index of machine windings, and phase to phase resistance measurements. They also visually inspected the stator laminations, windings, and the rotor.

The generator has only 4700 operating hours and NL Hydro records show that in recent years, it has rarely operated at above 10 MW. It is rated 14.15 MW. It should have a design life of over 40 years, but its insulation has suffered from age and possibly from rapid thermal cycling and condensation. The API unit can start and ramp to full load in about 2 minutes and during a fast start, the coils will suffer some thermal stress. Also, the unit experiences large temperature differences between the windings and the cooling air. There are no anti-condensation heaters. If the generator had operated with a high capacity factor for 45 years it would likely require a rewind.

Siemen's report shows that the insulation has deteriorated and there is a phase imbalance on the stator. Siemens recommend rewinding the stator. Table 2-5 compares the measured test results of the generator, exciter and major motors. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase imbalance is quite high and the cost of a stator rewind has been included in the refurbishment estimate.

**TABLE 2-5 COMPARISON OF SIEMENS TEST RESULTS ON GENERATOR AND MOTORS**

| | Resistance to Ground @ 1 Minute M ohm | Polarization of Windings | Phase to Phase Resistance |
|---|---|---|---|
| Generator Stator | 534 | 1.93 | 30% imbalance |
| Generator Rotor | 2.67 | 1.1 | |
| Exciter Stator | 534 | .96 | |
| Exciter Rotor | 2060 | 2.14 | Within 0.7% |
| AC Oil Pump Motor | 4600 | 1.15 | Within 0.17% |
| DC Oil Pump Motor | 185 | 0.93 | |
| AC Lube Oil Cooler Fan | 5520 | 1.37 | Within 0.67% |
| Fuel Oil Motors | 7920/1250 | 1.56/0.95 | Within 0.18% |

**Generator Exciter**

Siemens recommended an overhaul of the exciter, but there is some concern that an overhaul is not practical because the 45 year old unit is no longer supported by the OEM. Parts may not be available. On the other hand, it may be difficult to support the purchase of a new unit for a 8 year life extension.

**Summary**

In general, the unit is currently in poor condition and overdue for a major overhaul of many components. A tabular summary of the condition assessment of the gas turbine genset is provided below in Table 2-6:





## TABLE 2-6 CONDITION ASSESSMENT – GAS TURBINE GENSETS

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | GTG1 | 44 years old and has accumulated to 2010 about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007 | 4/10 | 150,000 (30) | 1 | 2020 | No | 1969 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | General | GTG2 | Overall Rolls Wood group inspection in 2010 concluded that the engine appears in reasonably good and serviceable condition.The engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. Coatings and some turbine blading and other components have suffered cracking or other damage. Corrosion/cracking from seaside moisture and starts. Buildup of salt on the first stages of the compressor. There is also cracking in the turbine section. Overdue for overhaul.Rear bearing housing in good condition.. | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Compressor and Intake | GTG3 | Rolls Wood reported: front bearing housing in good condition with medium loss of coating and corrosion,; VIGV bushes in good condition;bleed valves in good condiion, compressor stators in good clean condition with no defects; compressor casing surfaces in reasonably good condition with light to medium loss of coating and corrosion in some areas; compressor outlet casing in good condition with OGV having minor to medium loss of coating and corrosion to most surfaces; | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Combustor | GTG4 | Rolls Wood reported: carbon deposits on head sections and streaks down flame tube length;All in good conddition. | 4/10 | 150,000 (30) | 10 | 2020 | Yes | 2008 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Turbine Rotor | GTG5 | Rolls Wood reported: HP,IP andLP turbine blades intact and free of obvious defects. Exhaust assembly in good condition with minor surface corrosion. | 4/10 | 150,000 (30) | 5 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG6 | Received little attention since 1986 with very limited boropscope views of blade roots. Disk material in these limited views in the axially serrated root appears to be severely corroded.No way of knowing if corrosion is present on the remainder of the disk, and whether superficial or deep. Appears to extend under the root. It is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively the whole disk may be corroded. In either case the roots are very vulnerable to stress corrosion cracking.Overdue for overhaul. Greenray (legal representive of AEI gas turbines, hold all rights to their technology)do not think that the power turbine should be operated in its present condition. | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG7 | Greenray in its 2011 inspection noted: several circumferential cracks on inlet duct iner cone (previously seen in 2006) - no/limited propogation apparent; weld repairs on cone spokes inner downstream edges may be starting to fail; nozzle blade track corroded, heavily in places, and could cause failure of nozzle segment and shroud; blade tips irregular,possibly rubbed (little other evidence of blade tip rub); geneal corrosion (most light) on blading; rotor disc fir tree posts (for blades) heavily corroded in visible areas highly stressed areas - fialure could lead to catastrophic effect on power turbine components and appear to be propogating under rotor blade shoulder which could cause premature failure.; diffuser/volue generally corroded - effect on volute welding. | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Cooling Air | GTG8 | Turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading. | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER GEARBOX | Gearbox | GTG9 | Alba in 2007 indicated gearbox appeared to be in good condition and that if the bearings and seals are replaced the gearbox should not present a large risk. Issues remain on the cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft and must be determined and rectified. The high speed gearbox shaft seals are leaking and were the cause of a 2010 fire at the power turbine end of the gearbox which has resulted in the unit being limited to emergency use only. At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). Tests on the pressure in the gearbox (measured by a gauge mounted on the gearboxs casing) showed a rise with load and suggested that the gearbox is being pressurized by the Avon bleed air.<br>Greenray 2011 inspection: Gear wheels and internals appeared in pristne condition with normal marks. Outer wiper of leaking low speed gear wheel lube oil gland may be touching top of shaft and have some clearance at bottom (opposite to normal) and may indicate driven machine out of alignment with gearbox output shaft<br>The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008 Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.<br>Overdue for overhaul. | 4/10 | 150,000 (30) | 2 | 2020 | No | 1969 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | Generator | GTG10 | Siemen's report shows that the insulation has deteriorated and there is a phase inbalance on the stator. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase inbalance is quite high.<br>The generator compartment was provided with new filter elements which are in good condition, except that there are some holes in the building siding that allows some air to bypass them. | 4/10 | 200000 (40) | 5 | 2020 | No | 1969 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | Generator | GTG11 | Siemen's report rotor appears in good condition, that stator iron and wedging in good condition, some stator coil overheating, Stator insulation appeared dregraded, dry and flaking throughout, | 4/10 | 200000 (40) | 5 | 2020 | No | 1969 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE EXHAUST STACK | Exhaust Stack | GTG12 | Severly corroded, leaking,Braden 2011 inspection: exterior significant carbon steel crystallization and peeling of carbon steel; no fatigue/cracking of welds, sulging of stack on south side, several holes in exhaust. Snow hood no apparent issues (some operation issues with functionality). Transition duct (external insulation) not visible for inspection. Expansion joint belt in good condition. reported | 4/10 | (20) | 1 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA | Filter Material | GTG13 | Inlet housing and filtration system were replaced in 1986. Its stainless steel inlet splitters appear to have suffered little deterioration Water leaking into plenum.Filter media is considered inappropriate for its marine environment. The filter now has air gaps between the filter elements, due to rusting The high saline atmosphere means that the unit is operating with an increasingly ineffective inlet filter and the unit has suffered considerable degradation. | 4/10 | (30) | 2 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GOVENOR & FUEL CONTROL | | GTG14 | No specific informatioon on govenor and fuel control. Fuel control was an issue in 2007 Alba report with a recommendation to upgrade to address failed starts due to fuel control. Appears to have been completed.. | 4/10 | (30) | 5 | 2020 | No | 1986/2008 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | EXCITATION SYSTEM | | GTG15 | Siemens recommended an overhaul of the exciter and steam cleaning of windings, VPI testing of insulation. There is some concern that it is a 45 year old unit which is not supported. The polarization readings of the Exciter stator are poor. | 4/10 | (30) | 2 | 2020 | No | 1986 |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

## 2.1.5 Risk Assessment

**TABLE 2-7 RISK ASSESSMENT – GAS TURBINE GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Major Issues | Remaining Life Years | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Likeli--hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | GTG1 | 44 years old and has accumulated to 2010 about 4,717 hours with 1,548 starts. Four significant overhauls/repairs in 1978, 1986, and 1991 and a combustor replacement in 2007 | Major systems need overhaul | 1/10 | 4 | C | High | 3 | D | High | Major/catastrophic failure of unit or fire | Overhaul or replace |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | | GTG2 | Overall Rolls Wood group inspection in 2010 concluded that the engine appears in reasonably good and serviceable condition.The engine shows signs of pitting, salt deposition, corrosion and loss of coatings on the Avon gas generator. Coatings and some turbine blading and other components have suffered cracking or other damage. Corrosion/cracking from seaside moisture and starts. Buildup of salt on the first stages of the compressor. There is also cracking in the turbine section. Overdue for overhaul.Rear bearing housing in good condition.. | Blade failure or material realease causes downstream collateral damage. | 2 | 3 | C | Medium | 1 | D | Medium | Catastrophic failure of downstream equipment | Overhaul or replace |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG6/7 | Received little attention since 1986 with very limited boropscope views of blade roots. Disk material in these limited views in the axially serrated root appears to be severely corroded.No way of knowing if corrosion is present on the remainder of the disk, and whether superficial or deep. Appears to extend under the root. It is possible that salt particles have collected in the complex root form. The corrosion may be more serious in highly stressed areas, such as the root. Alternatively the whole disk may be corroded. In either case the roots are very vulnerable to stress corrosion cracking.Overdue for overhaul. Greenray (legal representive of AEI gas turbines, hold all rights to their technology)do not think that the power turbine should be operated in its present condition. | Power turbine rotor disck high stress blade root failure | 2 | 4 | C | High | 3 | D | High | Blade root failure of disk - catastrophic faiure | Replace/repair disk and overhaul unit. |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG8 | Turbine cooling air is taken directly from the environment, without filtration. Cooling air passes through an ejector, using Avon bleed air, so that the air reaching the disk is a mixture of filtered air from the Avon and unfiltered air. The disk cooling system has probably operated for 45 years with a significant salt loading. | Corrosion of power turbine blade roots. | 2 | 4 | C | High | 3 | D | High | Blade root failure of disk - catastrophic faiure | Modify air inlet. Replace/repair disk and overhaul unit. |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER GEARBOX | Gearbox | GTG9 | Alba in 2007 indicated gearbox appeared to be in good condition and that if the bearings and seals are replaced the gearbox should not present a large risk. Issues remain on the cause of the low oil pressure from the mechanical pump and the oil leak on the low speed drive shaft and must be determined and rectified. The high speed gearbox shaft seals are leaking and were the cause of a 2010 fire at the power turbine end of the gearbox which has resulted in the unit being limited to emergency use only. At least three or four causes have been suggested for the labyrinth oil seal leakage at the generator end (low speed shaft) and drive end (high speed shaft). Tests on the pressure in the gearbox (measured by a gauge mounted on the gearboxs casing) showed a rise with load and suggested that the gearbox is being pressurized by the Avon bleed air.<br>Greenray 2011 inspection: Gear wheels and internals appeared in pristne condition with normal marks. Outer wiper of leaking low speed gear wheel lube oil gland may be touching top of shaft and have some clearance at bottom (opposite to normal) and may indicate driven machine out of alignment with gearbox output shaft<br>The bearings may have suffered severe wear due to a number of possible causes (misalignment, gear backlash, or low gearbox oil pressure). In 2008 Alba noted that the splash plate behind the generator end seal was making contact with the shaft, which indicates heavy bearing wear.<br>Overdue for overhaul. | Gearbox oil leaks; gearbox misalignment/wear | 2 | 4 | C | High | 3 | D | High | Lube oil fires. (Gearbox failure (bearings/misalgnment) | Gearbox overhaul - seals, alignment, bearings |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | | GTG10/11 | Siemen's report shows that the insulation has deteriorated and there is a phase inbalance on the stator. The polarization readings of the generator stator are reasonable, and considerably better than those of the Exciter stator and the major motors. However the stator phase inbalance is quite high.<br>The generator compartment was provided with new filter elements which are in good condition, except that there are some holes in the building siding that allows some air to bypass them. | Generator insulation condiion and potential for failure | 5 | 3 | C | Medium | 3 | C | Medium | Generator winding failure and collateraldamage | Generator overhaul. Rewinds if necessary. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE EXHAUST STACK | Exhaust Stack | GTG12 | Severly corroded, leaking,Braden 2011 inspection: exterior significant carbon steel crystallization and peeling of carbon steel; no fatigue/cracking of welds, sulging of stack on south side, several holes in exhaust. Snow hood no apparent issues (some operation issues with functionality). Transition duct (external insulation) not visible for inspection. Expansion joint belt in good condition. reported | Stack water leakage into power turbine | 1 | 4 | C | High | 3 | C | Medium | Power turbine corrosion/failure. Stack failure | Replace stack |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA | Filter Material | GTG13 | Inlet housing and filtration system were replaced in 1986. Its stainless steel inlet splitters appear to have suffered little deterioration Water leaking into plenum.Filter media is considered inappropriate for its marine environment. The filter now has air gaps between the filter elements, due to rusting The high saline atmosphere means that the unit is operating with an increasingly ineffective inlet filter and the unit has suffered considerable degradation. | Corrosion impact on gas generator and power turbine causing failure | 2 | 3 | C | Medium | 3 | C | Medium | Corrosion of gas generator and power turbine accelerates. | Replace filter media; overhaul/repair housing. |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GOVENOR & FUEL CONTROL | | GTG14 | No specific informatioon on govenor and fuel control. Fuel control was an issue in 2007 Alba report with a recommendation to upgrade to address failed starts due to fuel control. Appears to have been completed.. | Failed starts and speed/load control | 5 | 2 | B | Low | 2 | B | Low | Unit start and control | Check status and refurbish as required as part of overhaul. |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | EXCITATION SYSTEM | | GTG15 | Siemens recommended an overhaul of the exciter and steam cleaning of windings, VPI testing of insulation. There is some concern that it is a 45 year old unit which is not supported. The polarization readings of the Exciter stator are poor. | Exciter failure; unit extended outage. | 2 | 3 | C | Medium | 3 | C | Medium | Failure of exciter leads to extended shutdown of unit. | Replace exciter. |

### 2.1.6 Actions

**TABLE 2-8 ACTIONS – GAS TURBINE GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | GTG1 | | | |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | General | GTG2 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Compressor and Intake | GTG3 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Combustor | GTG4 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Turbine Rotor | GTG5 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG6/7 | Purchase power turbine disk. No other specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Cooling Air | GTG8 | Modify cooling air to power turbine to eliminate salt ingress - part of major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER GEARBOX | Gearbox | GTG9 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | | GTG10/11 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE EXHAUST STACK | Exhaust Stack | GTG12 | Replacement stack and installation | 2012 | 1 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA | Filter Material | GTG13 | No specific capital Requirement - new fiolter media | 2012 | 2 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GOVENOR & FUEL CONTROL | | GTG14 | None | | |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | EXCITATION SYSTEM | | GTG15 | Refurbish exciter (Replace as necessary in refurbishment) | 2012 | 1 |

### 2.1.7 Life Assessment - Life Cycle Curves (Where equipment is not to be overhauled/replaced and life <2020 and has major unit operation impacts.)

The gas turbine *generator unit essentially requires all of its major components to be overhauled* or replaced as soon as practical. After such an overhaul, there should be no further major repairs required before 2020. Given this, no life cycle curves are presented for the gas turbine generator system.

### 2.1.8 Level 3 Inspections Required

The refurbishment of the unit can be done in two ways;

- NL Hydro can disassemble the unit and perform Level 3 inspection assessments on key equipment. After the assessments, NL Hydro will be able to obtain firm bids for replacement components and place orders for them. This will be a lengthy process and it will require Hydro to authorize a two phase investment; the first on disassembly and inspection and reassembly and the second for the purchase and fitting of replacement parts at some future date.
- Once NL Hydro makes a decision to refurbish the existing GT unit instead or replacing it with new GT or diesel generator facilities, those components identified as likely to require replacement should be ordered and the units overhauled. No level 3 inspections will be performed, although detailed inspections when during overhauls may show the need to refurbish other components. Large additional as-found overhaul costs are unlikely since a conservative approach in that any further major items will be required. Under this alternative independent Level 3 assessments are eliminated. This approach is recommended by AMEC.

Generally if the AMEC Recommended Approach is taken, no other “Level 3” inspections/tests are required.

If the first approach is taken, the most important Level 3 assessments are:

- Avon Gas Generator
- Power Turbine blade root condition
- Gearbox bearing wear/alignment and gearbox seals
- Disk cooling system

This approach may result in some savings in the final overhaul, but would require an additional outage and detailed inspections, and possibly additional delay in completing the final overhaul required.

### 2.1.9 Capital Enhancements

**TABLE 2-9 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE GENSETS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 0 | 0 | GAS TURBINE SYSTEM | GAS TURBINE SYSTEM | | GTG1 | | | |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | General | GTG2 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Compressor and Intake | GTG3 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Combustor | GTG4 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7308 | 0 | GAS TURBINE AVON JET ENGINE | GAS TURBINE AVON GAS GENERATOR | Turbine Rotor | GTG5 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Power Turbine | GTG6/7 | Purchase power turbine disk. No other specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER TURBINE | Cooling Air | GTG8 | Modify cooling air to power turbine to eliminate salt ingress - part of major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7058 | 0 | GAS TURBINE POWER TURB & G/B | GAS TURBINE POWER GEARBOX | Gearbox | GTG9 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7309 | 0 | GAS TURBINE GENERATOR | GAS TURBINE GENERATOR | | GTG10/11 | No specific capital projects - major unit overhaul. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE EXHAUST STACK | Exhaust Stack | GTG12 | Replacement stack and installation | 2012 | 1 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GAS TURBINE AIR INLET PLENUM CHAMBER & MEDIA | Filter Material | GTG13 | No specific capital Requirement - new fiolter media | 2012 | 2 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | GOVENOR & FUEL CONTROL | | GTG14 | None | | |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | EXCITATION SYSTEM | | GTG15 | Refurbish exciter (Replace as necessary in refurbishment) | 2012 | 1 |

### 2.1.10 Capital/Refurbishment and Overhaul Costs (Capital)

The Avon requires an overhaul to replace coatings and repair or replace turbine blading and other components which have suffered cracking or other damage. It is expected that when the Avon has been overhauled and the inlet filters replaced the Avon will not require further significant overhaul before life end in 2020, and that future annual maintenance costs would be less than $10,000 per year.

The first approach whereby limited funding is approved for disassembly and then make a second purchase decision when the equipment is examined is likely to be a slow process and possibly difficult administratively for NL Hydro. AMEC made assumptions based on data available, experience and recommendations from vendors such as Greenray, Alba Power, etc, and prepared an estimate covering all equipment which will probably be required for life extension. This is likely a quicker route to meet the project requirements, but has a risk of purchasing too much equipment.

AMEC received quotations from the following companies.

- Alba Power, Scotland.
- Greenray- the owner of AEI's original technology
- Camfil Farr- supplier of the inlet filter
- Braden - supplier of exhaust stacks
- SS Turbine services Ltd. - a small Canadian aero engine overhaul company.

In addition, AMEC has the quotation provided by 'Rolls Woods to NL Hydro for an Avon overhaul. This 2010 quotation is posted on Newfoundland Power Commission's website.

The pricing provided by Alba Power covers the entire plant, while other companies have only bid for their own equipment. The attached table shows the Alba Power bid, in column 1, with the bids from other companies in column 2. Column's 3 shows AMEC's estimate for the cost of providing a comprehensive rehabilitation to make the unit suitable for another 8 or more years of operation, with minimum risk. The major components, including the Avon, Power turbine, gearbox, generator, inlet filter and exhaust filter would be restored to the same condition as 1986. Column 3 is an amalgamation of the quotations received from the different companies, plus AMEC estimates for some minor costs.

The table assumes an exchange rate of 1.6 for the UK pound, and a modest 10% allowance for duty and freight.

Alba's cost of a complete "Standard Overhaul" of the Avon is included in column 3 but Alba did not include the cost of any required replacement parts. A full standard overhaul by Alba would therefore cost significantly more than the $500,000 which they bid, but it would give the Avon another 20,000 to 30,000 of life. S and S turbine have quoted $450,000 for a full overhaul including parts, which would include a proving test run after completion of the work. Even the work covered by this bid is probably excessive for the 8 year life extension required, but AMEC cannot judge how much work will be needed until the engine is disassembled. We have therefore allowed $500,000 for the Avon overhaul, including transportation.

Alba state that the unit will operate until 2020 with almost no additional cost, if the proposed overhaul is completed. In contrast to the comprehensive overhaul which Alba propose for the Avon, they have proposed simple on-site repairs of the inlet filter and exhaust stack, and a low cost overhaul of the generator and exciter.

**TABLE 2-10 CAPITAL COST ESTIMATE $ 1,000 CDN$**

| | Option 1 Alba total package | Option 2 Split supply | Composite estimate | Comments |
|---|---|---|---|---|
| | | Pound @ $1.6 | | |
| **Avon** | 500 | | 500 | Alba estimate is for a complete standard overhaul. O/H reports suggest some of this is not required. (note 1) |
| Replacement components | | | | Woods Rolls estimate $1.3 million for a complete Avon OH |
| | | | | S and S turbine quote $450,000 including parts. |
| **Power Turbine** | 300 | | | |
| Disassemble/reassemble | | 136 | 75 | Greenray estimate is substantially too high |
| New Disk | | 331 | 331 | Alba also have a disk; no quotation provided yet. |
| Moving blades | | See comment | 93 | 1 blade incl Greenway price- See note 1 |
| Rotor rehabilitation | | 282 | 282 | Includes shipment to UK |
| Inlet structure repairs | | | 15 | Small amount of welding is required |
| Thermocouples | | | | excluded from this estimate |
| Diaphragm section | | | 40 | |
| Heat shield | | | | |
| Bearings | | 70 | 70 | |
| Exhaust volute | | | 30 | Allow for minor repairs |
| **Gearbox** | | | | |
| Bearings | | 114 | 114 | |
| Disassemble/reassemble | | | | |
| Inspect, crack detection | | | | |
| Gearbox venting | | | 25 | Contingency against Greenray estimate |
| Contingency; 2nd opinion | | | 25 | Contingency against Greenray estimate |
| **Generator and aux** | 87 | | 900 | Alba confident cleaning & varnishing will improvelife |
| | | | | Rewind estimate requires confirmation. |
| Exciter | | | 50 | Refurbish (Replace as necessary during refurbishment) |
| **Inlet filter** | 30 | 588 | 150 | Camfil Farr est includes SS filter hours & new plenum. |
| | | | | For 8 year life extension new plenum not required, |
| **Exhaust stack** | 34 | 267 | 50 | For 8 year life extens existing stack with refurb adequate. |
| **Oil and fuel** | 45 | | 0 | This item covered by AMEC St Johns as BOP |
| Commission unit | | | 50 | |
| Contingency excl Avon | | | 150 | |
| **TOTAL** | 996 | 1788 | 2951 | |

Note 1. Alba quote $500,000 excluding parts, but overhaul scope is very extensive and can be reduced. S & S turbine is a smaller shop but quote $450,000 including all required parts.
Note 2. New PT blades from Greenray are very expensive. These blades can be welded, and as efficiency is not important we have estimate is based on a total of 4 new blades and weld repairs to others.

Assume 10% duty and shipping

## Schedule

The refurbishment of the unit can be done in two ways:

1. With the first alternative, NL Hydro can disassemble the unit in order to perform level 3 assessments on key equipment. After the Level 3 assessments, NL Hydro will be able to obtain firm bids for replacement components and place orders for them. This will be a lengthy process and it will require Hydro to authorize two separate contracts separated by several months. The first would cover disassembly and inspection and reassembly while the second would cover the purchase and fitting of replacement parts.

2. With the second alternative, AMEC will identify which components are likely to require replacement and that these are ordered if NL Hydro decides to refurbish the unit. Under this alternative, the unit will not receive any level 3 inspections until new components are available. It is possible that the detailed inspections will show the need for other component replacement, but AMEC thinks that it is unlikely that any further major long lead items will be required. The most expensive item which may have to be purchased is the power turbine disk, but NL Hydro will have the choice of purchasing a stock unit from Alba, if it is still available, or a new unit from Greenray.

The most important level 3 assessments are:

- Avon Gas Generator (The actual scope of the overhaul will be adjusted when the unit is inspected at the beginning of the overhaul).
- Gearbox and seals
- Power turbine Disk cooling system
- Power turbine disk
    - Diaphragms and diaphragm ring

The schedule suggested by Greenway for the Power Turbine, with some additions identified for the other components, is shown in Table 2-11:

**TABLE 2-11 HOLYROOD GT REFURBISHMENT SCHEDULE**

Newfoundland and Labrador Hydro. Holyrood GT refurbishment

| | week | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Manufacture Disc | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Strip and dissassemble plant | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Ship Rotor to overhaul plant | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Overhaul and balance Rotor | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Ship Rotor to Holyrood | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Rebuild and commission unit | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Avon overhaul | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Generator Refurbish (Rewind as necessary) | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

## 2.2 Electrical & Controls Equipment/Processes

| | |
|---|---|
| Unit #: | GAS TURBINE |
| Asset Class # | BU 1273 Gas Turbine |
| SCI & System: | 7202 Gas Turbine System |
| Sub-Systems: | 7310 HRD GT E&C |

### 2.2.1 Description of Existing System

Holyrood GS consists of three thermal units (2x175 MW and 1x150 MW). Each unit supplies its own station service 4160V bus when on line. The Common station service for Unit #1 and #2 is fed from a 69KV/4160V 10.5/14MVA transformer SST-12. The Common station services of Unit #1 are fed from a 69KV/4160V 10.5/14MVA transformer SST-34. When the unit is shutdown (off line) its unit station service bus is transferred to the Common station services source (Reference - Holyrood Single Line Electrical Diagram).

During a total loss of all station service supply the station can be re-started from blackout condition with the 13.5 MW, 13.8 KV Emergency Gas Turbine (GT) connected to the 4160V station service bus through a 10.5 MVA step down transformer (T9). The station service buses all have a ground fault current limited to 1000A by a Neutral Ground Resister (NGR) of 2.4 Ohms.

References:

- NFL Holyrood Single Line Drawing # A)-1403-500-E-001 Rev 16
- IEEE C62.92-1989 Guide for the application of Neutral Grounding in Electrical Utility System Part II Grounding of Synchronous generator system.

Within the GT building, the Electrical and Control systems consist of a rotting brushless exciter, an automatic voltage regulator (AVR), a start rectifier, Distributed Control System (DCS) control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment.

The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960's. The governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit controls its stator terminal voltage (13.8 kV) and MVAr delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and megawatt (MW) loading. In 1987, the Gem 80/500 PLC replaced all relay logic, but in 2009 this was again replaced by a Foxboro (Invensys) system which is in communication with the Plant DCS, and is now the primary controlling medium for the gas turbine.

The excitation control system consists of a "Normal" and "Standby" automatic voltage regulator (AVR) backed up by a "Manual" control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

**Governor and Fuel Control:** The standard Avon fuel control system is used without alteration as a basis for the API governing and fuel control system. The throttle valve is used as a generator valve and the HP cock as a fuel shut-off valve for normal and emergency shut-downs. The governing system is of the sensitive oil type in which fluid pressure is used to transmit the movement of the governor pilot valve to the operating mechanism of the governor valve, in this case the Avon throttle.

The governor is manufactured by Woodward and is driven via gearing from the end of the high speed pinion shaft. The governor is a fly-weight type and carries its own oil supply.

Woodward Governor suggests that the present system has a reliability of about 50%. In addition spare parts for this system are not carried and would have to be fabricated requiring long delivery times.

The governor, synchronizer and monitoring equipment were newly installed in 1986. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and MW loading.

**Excitation System:** The exciter is a rotating brushless type mounted on a stub to the main rotating shaft. It was designed to ANSI Specification C50-13. The AC output from the exciter armature is fed through a set of diodes that are mounted on the rotor and are used to produce a DC voltage. The voltage is fed directly to the field winding of the main generator which is also mounted on the same rotating shaft.

The excitation control system consists of a “Normal” and “Standby” automatic voltage regulator (AVR) backed up by a “Manual” control mode. The AVR controls the strength of the magnetic field in the exciter by varying the amount of current through the stationary exciter field windings.

**Switchgear:** Primary voltage generated by the GT is 13,300 Volts. The installed GT capacity is 13.5 MW, however based on limiting factors the unit sees normal operation of ~12 MW. Originally this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT’s) in this breaker. These CT’s are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB12. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

**600V Standby Power:** GT 600 V standby power for the MCC and auxiliaries is fed from the diesel generator bus DB34 or power centre ‘C’ via a manual transfer switch in the control room. This item feeds into an automatic transfer switch which alternately is fed from the 112 kVA transformer in the previous paragraph.

**Battery Room:** A battery room is located adjacent to the room that contains the MCC and switchgear. The room (approximately 1800mm-2700mm) controls a bank of batteries for the purpose of powering the DC powered emergency lubrication pumps for the GT lubrication system should the shaft driver and the AC driver lubricating pumps fail during operation of the GT. The battery system also provides a source of power to the DC lube oil pump, should the AC power supply from the station Diesel Generators or Utility power to the GT building be lost.

**GTG Control System**

The control system has been incrementally improved through the unit’s life. In 1970, a PLC was installed to improve overall startup and unit control. In 1986, the Gem 80/500 PLC replaced all relay logic and was the primary controlling medium for the gas turbine. In 2009, it was replaced with an Invensys (Foxboro) DCS and the PLC logic was converted to DCS logic. The DCS controls the sequencing functions of the GT as did the PLC. It is set up on the plant DCS network so that the screens can be viewed by the plant

operator in the main control room. In 2009, this was replaced by a Foxboro DCS system, which has greatly improved graphics.

**Control Room & MCC/Switchgear Room**

Within the gas turbine building, the electrical and control systems consist of a rotating brushless exciter, an automatic voltage regulator (AVR), a start rectifier, PLC control modules, motor control centre (MCC), electronic governors, synchronizer, and protection and monitoring equipment. The brushless exciter, AVR and start rectifier were manufactured by AEI Limited of Manchester, England in the mid-1960s. The programmable logic controller (PLC), governor, synchronizer and monitoring equipment were newly installed in 1986. The exciter and AVR unit act in combination to supply a controlled DC current to the wound rotor of the main generator which in turn controls its stator terminal voltage (13.8 kV) and MVar delivery. The start rectifier converts station AC current into the high DC current necessary to rotate the jet engine to ignition. The governor consists of two Woodward units: one that controls the jet acceleration on start-up and the second that controls the power turbine/generator during synchronization and MW loading.

**Switchgear**

The primary voltage generated by the GT is 13,300 Volts. The installed GT capacity is 13.5 MW. However, based on limiting factors, the unit sees normal operation of less than 12 MW.

Originally, this power was fed through a 13.8 kV oil circuit breaker and then through a 13.8 kV fusible switch. The oil circuit breaker is no longer functional but remains installed due to the current transformer (CT's) in this breaker. These CT's are essential to the protection of the generator and the 13.8 kV/4.160 14 MVA transformer. Power is then fed from the transformer at 4.160 kV to breaker SSB-2 in station panelboard SB1 2. Power from the CT or station power also feeds a 13.8 kV fused disconnect switch through a 75 kVA 13.8 kV/575 V transformer that provides power back to the station system.

### 2.2.2 Major Maintenance History

In 1987, the original control panel and sequencing system was removed and replaced with a state of the art programmable control and sequence system (Pratt & Whitney). This system was subsequently replaced in 2009 by a Foxboro (Invensys) DCS system. The original AEI/GEC control system was removed and replaced with a Woodward Governor 2301 Control System driving an EGP3 actuator.

Other than the decision to bypass the 13.8kV oil circuit breaker, no major maintenance has been carried out.

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

**25 May 2007**

- Ignitor, lead and box were replaced;

**21 May 2008**

- Controls review.

**10 June 2008**

- Fuel pump and fuel control unit (FCU) to be repaired.

**15 October 2009**

- Thermocouple damage, quick fixed. To be upgraded;

**20 November 2009**

- Commissioning;
- Fuel control solenoid valve burnt out and replaced;
- Multiple start trips due to low fuel pressure, low oil pressure, and incomplete start sequence. Several issues identified - igniter box malfunction, N2 probe incorrectly connected & poor FCU actuator tuning;
- Suggest monitoring setup for the 8 EGT thermocouples.

NL Hydro has since undertaken a number of activities with vendors that have the OEM rights to the GT sections in order to conduct detailed internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates. None dealt specifically with the electrical and control (E&C) systems.



## 2.2.3 Condition Assessment & Remaining Life

**TABLE 2-12 CONDITION ASSESSMENT – GT ELECTRICAL & CONTROLS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 7202 | 7310 | 0 | Elect and Control | 800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17) | 2.3.3.2 a) | EC1 | The breaker has been by-passed, but does not comprimise the protection of the Generator or T9 Transformer, as the protection still disables the excitation and trips SSB-2 on Statron Board SB12, and at the same time removes internal faults on the Generator and T9 Transformer | 4/10 | | N/A | N/A | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2) | 2.3.3.2 b) | EC2 | Support and spares are unavailable | 4/10 | | N/A | N/A | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical) | Part of - 2.3.3.2 c) | EC3 | Good Condition | 4/10 | | 10+ | 2020 | Yes | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph manual transfer switch (Square D) | N/A | EC4 | Fair Condition, but no spares available | 4/10 | | 10+ | 2020 | Yes | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls) | N/A | EC5 | Fair Condition, but no spares available | 4/10 | | 10+ | 2020 | Yes | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 600V, 3ph, Dist. Panel | N/A | EC6 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | 4/10 | | 0 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car F70P) | Part of - 2.3.3.2 e) | EC7 | Good Condition | 4/10 | | 10+ | 2020 | Yes | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | MCC (AEI, Type MMC Series 1000) | 2.3.3.2 d) | EC8 | Contains 600V, 3ph, 230V, 3ph and 100V dc bussing. The MCC is not only obsolete, with no spares or documentation available, but also violates CEC C22.1 working space in front of the MCC is less than 1 metre and when a starter is drawn out there is a safety hazard in front of the MCC. | 4/10 | | 0 | 2012 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 100A, 230V, 3ph lighting panel | N/A | EC9 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | 4/10 | | 1 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc dist. Panel | N/A | EC10 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | 4/10 | | 1 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | N/A | EC11 | Part of existing MCC | 4/10 | | 0 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | 230V, 3ph, starter and disconnect | N/A | EC12 | Part of existing MCC | 4/10 | | 0 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | Battery Charger (SAFT NIFE, Model SLRF 120-30) | N/A | EC13 | Good Condition | 4/10 | | 10+ | 2020 | Yes | 1995 |
| | 7202 | 7310 | 0 | Elect and Control | 129V dc battery bank (C&D technologies) | N/A | EC14 | The battery has a life expectancy of 18-25 years. Being situated in a good environment, not over-stressed and receiving regular maintenance. Product is current with replacement cells and spare parts available. | 4/10 | | 10+ | 2020 | Yes | 1995 |
| | 7202 | 7310 | 0 | Elect and Control | Start rectifier (AEI) | 2.3.3.2 g) | EC15 | No maintenance or servicing has been carried out by the present maintenance staff. | 4/10 | | 0 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | Automatic voltage regulator/excitor (AEI) | 2.3.3.2 g) | EC16 | No maintenance or servicing has been carried out by the present maintenance staff. | 4/10 | | 0 | 2020 | No | 1969 |
| | 7202 | 7310 | 0 | Elect and Control | Protection and Controls (Pratt & Whitney) | N/A | EC17 | Very good condition, with spares available for the unforseen future | 4/10 | | 10+ | 2020 | Yes | 1986 |
| | 7202 | 7310 | 0 | Elect and Control | DCS (Foxboro/Invensys) | N/A | EC18 | Good condition - replaces the GEN80 PLC system and communicates direct into the plant DCS. DCS in operation considered "state-of-the-art" and replacement service agreement renders the system current. | 4/10 | | 10+ | 2020 | Yes | 2009 |
| 1325 | 5983 | 5983 | 61-00-69576 | TRANSFORMERS | TRANSFORMER T9 | 13.8 kV | EC19 | Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric test performed in 1983. The latest Planned Maintenance was in 2006. Insulating oil tests in 2009 suggests higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products. | 4 | (45) | 5+ | 2020 | Yes | 1970 |

## 2.2.4 Risk Assessment/

**TABLE 2-13 RISK ASSESSMENT – GT ELECTRICAL & CONTROLS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Major Issues | Remaining Life Years | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| | 7202 | 7310 | 0 | Elect and Control | 800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17) | 2.3.3.2 a) | EC1 | The breaker has been by-passed, but does not comprimise the protection of the Generator or T9 Transformer, as the protection still disables the excitation and trips SSB-2 on Statron Board SB12, and at the same time removes internal faults on the Generator and T9 Transformer | Arc flash | 0 | 1 | D | Medium | 1 | 4 | Medium | Arc Flash on breaker resulting in potential for serious injury. | Breaker has been by-passed |
| | 7202 | 7310 | 0 | Elect and Control | 13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2) | 2.3.3.2 b) | EC2 | Support and spares are unavailable | Not able to maintain | 0 | 4 | A | Low | 4 | 1 | Medium | None likely in current configuration. | replace with new fusible switch |
| | 7202 | 7310 | 0 | Elect and Control | 112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical) | Part of - 2.3.3.2 c) | EC3 | Good Condition | None | 10+ | 1 | B | Low | 1 | C | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph manual transfer switch (Square D) | N/A | EC4 | Fair Condition, but no spares available | Not able to maintain | 10+ | 1 | A | Low | 1 | A | Low | N/a | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls) | N/A | EC5 | Fair Condition, but no spares available | Not able to maintain | 10+ | 1 | A | Low | 1 | A | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | 600V, 3ph, Dist. Panel | N/A | EC6 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | Not able to maintain | 0 | 4 | A | Low | 3 | A | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | 30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) | Part of - 2.3.3.2 e) | EC7 | Good Condition | None | 10+ | 1 | B | Low | 1 | C | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | MCC (AEI, Type MMC Series 1000) | 2.3.3.2 d) | EC8 | Contains 600V, 3ph, 230V, 3ph and 100V dc bussing. The MCC is not only obsolete, with no spares or documentation available, but also violates CEC C22.1 working space in front of the MCC is less than 1 metre and when a starter is drawn out there is a safety hazard in front of the MCC. | Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc | 0 | 4 | C | High | 3 | D | High | Arc flash and threat of personell serios injury | Replace the MCC and Re-Cable the 600V, 230V and 110V DC power. |
| | 7202 | 7310 | 0 | Elect and Control | 100A, 230V, 3ph lighting panel | N/A | EC9 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | Not able to maintain | 1 | 4 | A | Low | 3 | B | Medium | Lighting failure - staff safety | Replace the Start Rectifier |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc dist. Panel | N/A | EC10 | Fair condition, but distribution board and branch breakers are old with no spares available and have been superceeded by up-to-date equipment. | Not able to maintain | 1 | 4 | C | Medium | 3 | C | Medium | Unit failure to start- extended period. | Replace the Start Rectifier |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | N/A | EC11 | Part of existing MCC | Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc | 0 | 3 | C | High | 2 | D | High | Arc flash and threat of personell serios injury | Replace the Starter and the Fused Disconnect |
| | 7202 | 7310 | 0 | Elect and Control | 230V, 3ph, starter and disconnect | N/A | EC12 | Part of existing MCC | Obsolete unable to maintain. Does not conform to Candian Standards Maintance and Arc | 0 | 4 | C | High | 3 | D | High | Arc flash and threat of personell serios injury | Replace the Starter and the Fused Disconnect |
| | 7202 | 7310 | 0 | Elect and Control | Battery Charger (SAFT NIFE, Model SLRF 120-30) | N/A | EC13 | Good Condition | None | 10+ | 1 | A | Low | 1 | B | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | 129V dc battery bank (C&D technologies) | N/A | EC14 | The battery has a life expectancy of 18-25 years. Being situated in a good environment, not over-stressed and receiving regular maintenance. Product is current with replacement cells and spare parts available. | None | 10+ | 1 | A | Low | 1 | B | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | Start rectifier (AEI) | 2.3.3.2 g) | EC15 | No maintenance or servicing has been carried out by the present maintenance staff. | Not able to maintain | 0 | 1 | C | Medium | 3 | C | Medium | Unit failure to start- extended period. | Replace the Start Rectifier |
| | 7202 | 7310 | 0 | Elect and Control | Automatic voltage regulator/excitor (AEI) | 2.3.3.2 g) | EC16 | No maintenance or servicing has been carried out by the present maintenance staff. | Not able to maintain | 0 | 1 | C | Medium | 3 | C | Medium | Unit failure to start- extended period. | Replace the Automatic Voltage Regulator |
| | 7202 | 7310 | 0 | Elect and Control | Protection and Controls (Pratt & Whitney) | N/A | EC17 | Very good condition, with spares available for the unforseen future | None | 10+ | 1 | A | Low | 1 | B | Low | N/A | Monitor condition. |
| | 7202 | 7310 | 0 | Elect and Control | DCS (Foxboro/Invensys) | N/A | EC18 | Good condition - replaces the GEN80 PLC system and communicates direct into the plant DCS. DCS in operation considered "state-of-the-art" and replacement service agreement renders the system current. | None | 10+ | 1 | A | Low | 1 | B | Low | N/A | Monitor condition. |
| 1325 | 5983 | 5983 | 61-00-69576 | TRANSFORMERS | TRANSFORMER T9 | 13.8 kV | EC19 | Installed in 1970, the unit is at a high level of risk due to its age. No significant issues were identified in Doble tests last done in 2001. Maintenance in 2000, 2004 and 2006 was for various gauges/relays. Silica gel was replaced in 2002 and a Dielectric | Transformer failure | 5+ | 2 | C | Medium | 2 | C | Medium | Transformer core failure; oil leak etc. | Monitor condition and gas and oil tests per schedule. |

### 2.2.5 Actions

**TABLE 2-14 ACTIONS – GT ELECTRICAL & CONTROLS**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| | 7202 | 7310 | 0 | Elect and Control | 800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17) | 2.3.3.2 a) | EC1 | replace 13.8kV breaker, and recommend that a new SSB-2, vacuum interrupting type , 4160V, be installed in station board Sb12, complete with Rm trip and arc flash maintenance reduction switch. | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | 13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2) | 2.3.3.2 b) | EC2 | Replace fusable switch | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | 112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical) | Part of - 2.3.3.2 c) | EC3 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph manual transfer switch (Square D) | N/A | EC4 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls) | N/A | EC5 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | 600V, 3ph, Dist. Panel | N/A | EC6 | Recommend replacing with new dist. Panel and breakers | 2012 | 2 |
| | 7202 | 7310 | 0 | Elect and Control | 30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) | Part of - 2.3.3.2 e) | EC7 | No reocmmended action | | |
| | 7202 | 7310 | 0 | Elect and Control | MCC (AEI, Type MMC Series 1000) | 2.3.3.2 d) | EC8 | Replace with new MCC for the 600V, 3ph system (also reference items 11 and 12) | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | 100A, 230V, 3ph lighting panel | N/A | EC9 | Recommend replacing with new lighting panel and breakers | 2012 | 2 |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc dist. Panel | N/A | EC10 | Recommend replacing with new dist. Panel and breakers | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | N/A | EC11 | Recommend replacing with a new starter for the Hyd, Gov Pump and new disconnect for the 100V dc panel feed. | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | 230V, 3ph, motor starter and fused disconnect | | EC12 | Recommend replacing with a new starter for the air compressor and new disconnect for the new ACR controls | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | battery charger | | EC13 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | 129V dc battery bank | | EC14 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | Start rectifier | | EC15 | Recommend replacing with a new system | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | AVR | | EC16 | Recommend replacing with a new system | 2012 | 1 |
| | 7202 | 7310 | 0 | Elect and Control | Prot. & Controls | | EC17 | No recommended action | | |
| | 7202 | 7310 | 0 | Elect and Control | DCS | | EC18 | No recommended action | | |

### 2.2.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The newer equipment (Controls, battery chargers, batteries) can all meet the 2020 end date. The balance (AVR, MCC, etc.) essentially should be replaced as part of any refurbishment program. Post refurbishment in line with the proposals in this report, there should be no further major significant repairs required before 2020.

### 2.2.7 Level 3 Inspections Required

No incremental to refurbishment Level 3 assessments are required.

### 2.2.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-15.

**TABLE 2-15 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE ELECTRICAL & CONTROLS**

| Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|
| 7202 | 7310 | 0 | Elect and Control | 800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17) | 2.3.3.2 a) | EC1 | Removal of existing breaker and installation of new breaker, trays and new JB. Run power cables from new breaker to generator and to T9 tranformer, Termination of existing CT's, PT's and control cables in new JB, and extending new CT, PT and control cables from new JB to the new breaker, Extend grounding as necessary. Function test and commission. | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | 13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2) | 2.3.3.2 b) | EC2 | Removal of existing fusible switch and installation of new fusible switch, plus installation of cabling to 112 kVA transformer. Ground as necessary. Function test and commission | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | 112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical) | 2.3.3.2 c) | EC3 | Cable from 112kVA Transformer to new 13.8kV Fusible Switch | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | MCC (AEI, Type MMC Series 1000) | 2.3.3.2 d) | EC8 | Replace the MCC and Re-Cable the 600V, 230V and 110V DC power. | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | 30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) ; New 230V, 3ph, Auxiliary Distribution Panel | 2.3.3.2 e) | EC7 | Install New 230V, 3ph, Auxiliary Distribution Panel. Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | 2.3.3.2 f) | EC11 | New 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel. New Feeders from Splitter to DC Starters and DC Distribution Panel | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Start rectifier (AEI) | 2.3.3.2 g) | EC15 | Replace the Start Rectifier | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Automatic voltage regulator/excitor (AEI) | | EC16 | Replace the Automatic Voltage Regulator | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Miscellaneous | 2.3.3.2 h) | EC20 | Miscellaneous Hardware, Tray and 4/0 Grounding | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Commissioning | | EC21 | Commissioning | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Protection and Controls (Pratt & Whitney) | | EC17 | No Capital Required | | |
| 7202 | 7310 | 0 | Elect and Control | DCS (Foxboro/Invensys) | | EC18 | No Capital Required | | |
| 5983 | 5983 | 61-00-69576 | TRANSFORMERS | TRANSFORMER T9 | | EC19 | No Capital Required | | |
| 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph manual transfer switch (Square D) | | EC4 | No Captial Requirement | | |
| 7202 | 7310 | 0 | Elect and Control | 200A, 600V, 3ph automatic transfer switch (Taylor Industrial Controls) | | EC5 | No Captial Requirement | | |
| 7202 | 7310 | 0 | Elect and Control | 600V, 3ph, Dist. Panel | | EC6 | No Capital Required | | |
| 7202 | 7310 | 0 | Elect and Control | 100A, 230V, 3ph lighting panel | | EC9 | No Captial Requirement | 2012 | 2 |
| 7202 | 7310 | 0 | Elect and Control | 120V dc dist. Panel | | EC10 | No Captial Requirement | 2012 | 2 |
| 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | | EC11 | Replace the Starter and the Fused Disconnect | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | 230V, 3ph, starter and disconnect | | EC12 | Replace the Starter and the Fused Disconnect | 2012 | 1 |
| 7202 | 7310 | 0 | Elect and Control | Battery Charger (SAFT NIFE, Model SLRF 120-30) | | EC13 | No Capital Required | | |
| 7202 | 7310 | 0 | Elect and Control | 129V dc battery bank (C&D technologies) | | EC14 | No Capital Required | | |

### 2.2.9 Capital/Refurbishment and Overhaul Costs (Capital)

The suggested equipment and installation costs (Refurbishment of Existing Equipment) for the GT E&C systems are presented in Table 2-16.

**TABLE 2-16 CAPITAL COST ESTIMATE – GAS TURBINE ELECTRICAL & CONTROLS**

| Asset #2 | Asset #3 | Asset #4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority | Desciption | Qty | Unit | Material | Labour | Total | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7202 | 7310 | 0 | Elect and Control | 800A, 13.8 kV Generator Main Breaker (AEI, Type BRP17 / BVRP17) | 2.3.3.2 a) | EC1 | Removal of existing breaker and installation of new breaker, trays and new JB. Run power cables from new breaker to generator and to T9 tranformer, Termination of existing CT's, PT's and control cables in new JB, and extending new CT, PT and control cables from new JB to the new breaker, Extend grounding as necessary. Function test and commission. | 2012 | 1 | Installation of new 800A, 13.8 kV, 3ph, 60Hz Generator Main Breaker | 1 | ea | 126860 | 12800 | 139660 | |
| | | | | | | | | | | Removal of Existing Main Breaker | 1 | lot | - | 1600 | 1600 | |
| | | | | | | | | | | Installation of Cable Tray | 20 | m | 3500 | 1250 | 4750 | |
| | | | | | | | | | | Installation of New Junction Box | 1 | ea | 1000 | 480 | 1480 | |
| | | | | | | | | | | Removal of Existing Power Cables from Existing Breaker to Generator and T9 Transformer | 1 | lot | - | 1600 | 1600 | |
| | | | | | | | | | | Installation of New Power Cables from New Breaker to Generator (2 x 500kcmil) and T9 Transformer (2x500kcmil) | 180 | m | 50,000 | 10,000 | 60,000 | |
| | | | | | | | | | | Connection of Existing and Used CT, PT and Control Cables in New JB, and run the new CT, PT and Control Cables from new JB to new 13.8 kV Main Breaker (4 x 4c10, 1 x 4c12, 1 x 12c12). | 1 | lot | 600 | 1600 | 2200 | |
| 7202 | 7310 | 0 | Elect and Control | 13.8 kV fusible switch (J.G. Statter, Ltd. Type VLMK2) | 2.3.3.2 b) | EC2 | Removal of existing fusible switch and installation of new fusible switch, plus installation of cabling to 112 kVA transformer. Ground as necessary. Function test and commission | 2012 | 1 | Installation of New 13.8kV Fusible Switch | 1 | ea | - | - | | included with cost of 13.8kV |
| | | | | | | | | | | Removal of Existing 13.8 kV Fusible Switch | 1 | lot | - | 1600 | 1600 | |
| 7202 | 7310 | 0 | Elect and Control | 112 kVa, 13.8 kV: 600V 3ph Transformer (Cart 6 Electrical) | 2.3.3.2 c) | EC3 | Cable from 112kVA Transformer to new 13.8kV Fusible Switch | | | Install 3c2AWG, Teeck, 15kV, Cable from 112kVA Transformer to new 13.8kV Fusible Switch | 10 | m | 750 | 300 | 1050 | |
| 7202 | 7310 | 0 | Elect and Control | MCC (AEI, Type MMC Series 1000) | 2.3.3.2 d) | EC8 | Replace the MCC and Re-Cable the 600V, 230V and 110V DC power. | 2012 | 1 | Remove Existing MCC | 1 | ea | - | 8000 | 8000 | |
| | | | | | | | | | | Install New MCC | 1 | ea | 30000 | 8000 | 38000 | |
| | | | | | | | | | | Install Cable Tray | 1 | lot | 1600 | 900 | 2500 | |
| | | | | | | | | | | Install New Incoming and Feeder Cables for 600V Circuits | | | | | | |
| | | | | | | | | | | 3C12, Teck, 1000V, (Seven Circuits) | 280 | m | 1260 | 525 | 1785 | |
| | | | | | | | | | | 3c10, Teck, 1000V, (One Circuit) | 40 | m | 240 | 120 | 360 | |
| | | | | | | | | | | 3c6, Teck, 1000V, (Five Circuits) | 200 | m | 1025 | 350 | 1375 | |
| | | | | | | | | | | 3c2, Teck, 1000V, (One Circuit) | 40 | m | 1040 | 200 | 1240 | |
| 7202 | 7310 | 0 | Elect and Control | 30 kVa, 600V: 230/115V, 1ph lighting transformer (Hammond, Type F Car FZ9P) ; New 230V, 3ph, Auxiliary Distribution Panel | 2.3.3.2 e) | EC7 | Install New 230V, 3ph, Auxiliary Distribution Panel. Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel | | | Install New 230V, 3ph, Auxiliary Distribution Panel | 1 | ea | 650 | 350 | 1000 | |
| | | | | | | | | | | Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel | 1 | lot | - | 3000 | 3000 | |
| | | | | | | | | | | 3c12, Teck, 1000V (One Circuit) | 40 | m | 180 | 75 | 255 | |
| | | | | | | | | | | 3c10, Teck, 1000V, (Two Circuits) | 40 | m | 120 | 60 | 180 | |
| 7202 | 7310 | 0 | Elect and Control | 120V dc motor starters fused disconnect | 2.3.3.2 f) | EC11 | New 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel. New Feeders from Splitter to DC Starters and DC Distribution Panel | | | Install new 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel | 1 | lot | 31000 | 6400 | 37400 | |
| | | | | | | | | | | Install New Feeders from Splitter to DC Starters and DC Distribution Panel | | | | | | |
| | | | | | | | | | | 3c12, Teck, 1000V (One Circuit) | 40 | m | 180 | 75 | 255 | |
| | | | | | | | | | | 3c10, Teck, 1000V, (One Circuit) | 35 | m | 210 | 120 | 330 | |
| | | | | | | | | | | 3c2, Teck 1000V (One Circuit) | 16 | m | 410 | 140 | 550 | |
| 7202 | 7310 | 0 | Elect and Control | Start rectifier (AEI) | 2.3.3.2 g) | EC15 | Replace the Start Rectifier | 2012 | 1 | Remove Existing AVR/Start Rectifier | 1 | ea | - | 1600 | 1600 | |
| 7202 | 7310 | 0 | Elect and Control | Automatic voltage regulator/excitor | | EC16 | Replace the Automatic Voltage Regulator | 2012 | 1 | Install New AVR/Start Rectifier | 1 | ea | 145,000 | 20,000 | 165,000 | |
| 7202 | 7310 | 0 | Elect and Control | Miscellaneous | 2.3.3.2 h) | EC20 | Miscellaneous Hardware, Tray and 4/0 Grounding | 2012 | 1 | Miscellaneous Hardware, Tray and 4/0 Grounding | 1 | lot | 7500 | 7500 | 15000 | |
| 7202 | 7310 | 0 | Elect and Control | Commissioning | | EC21 | Commissioning | 2012 | 1 | Commissioning Costs | | | - | 50,000 | 50000 | |

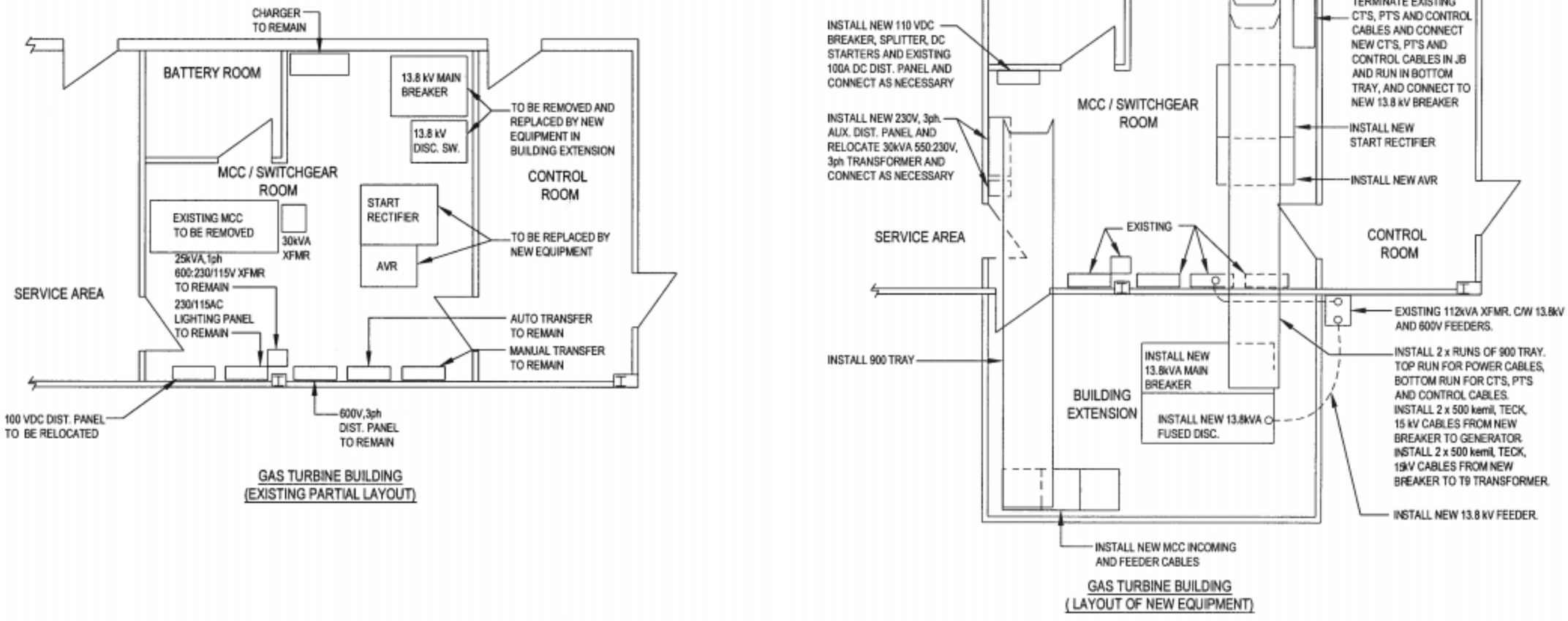



**FIGURE 2-2 GAS TURBINE BUILDING – ELECTRICAL & CONTROLS – CURRENT AND PROPOSED**

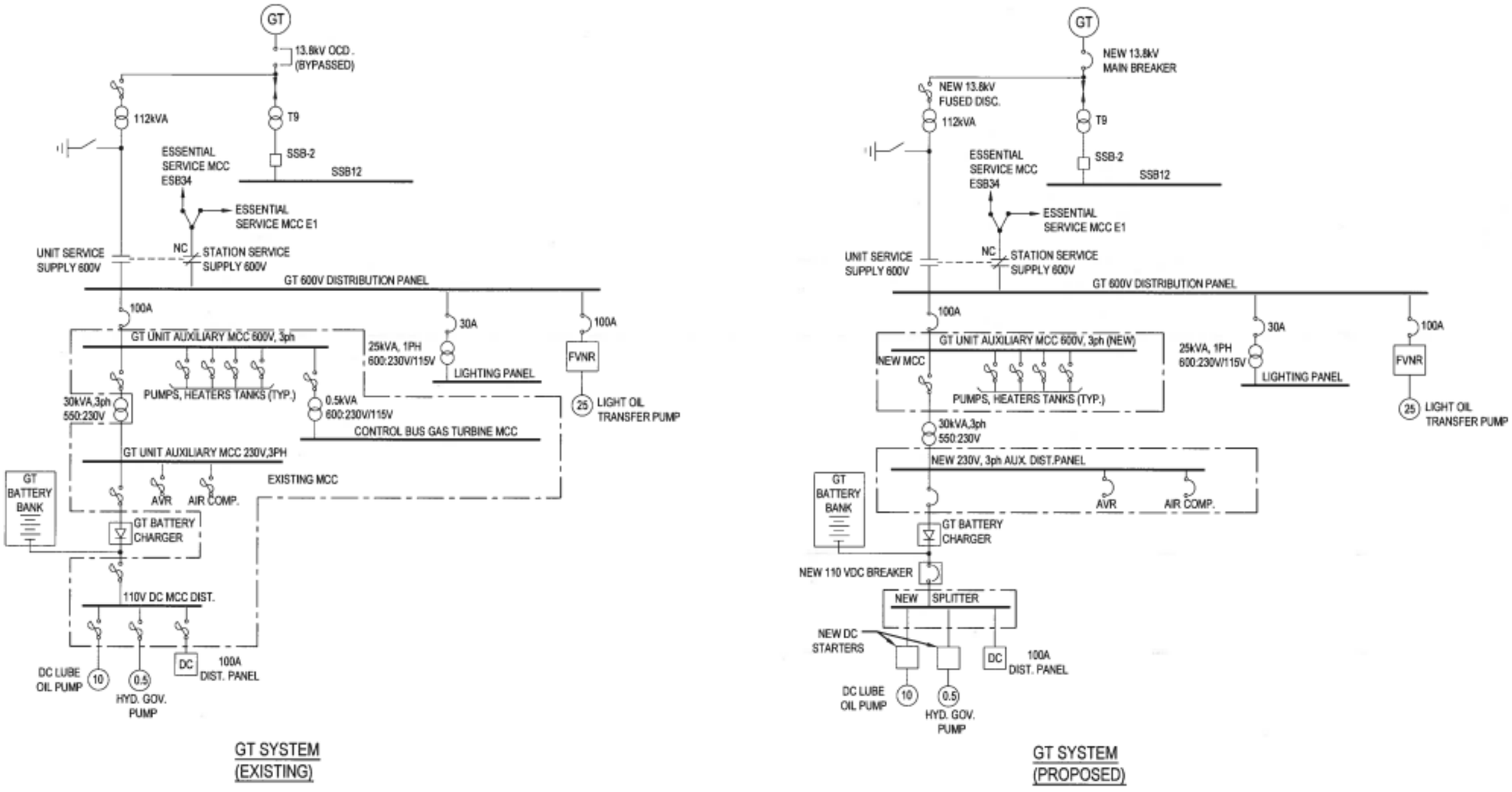



**FIGURE 2-3 GAS TURBINE SINGLE LINE DIAGRAMS – CURRENT AND PROPOSED**

## 2.3 Gas Turbine Balance of Plant (BOP) Equipment/Processes

| | |
|---|---|
| Unit #: | GAS TURBINE |
| Asset Class # | BU 1273 Gas Turbine |
| SCI & System: | 7202 Gas Turbine System |
| Sub-Systems: | 7311 GT Aux Systems |

### 2.3.1 Description

**AC Lube Oil Cooler:** The AC Lube Oil Cooler is located outside the GT building. The cooler has experienced a substantial amount of surface corrosion due to the environment. The fan is controlled by temperature logic in the lubricating oil loop. A thermostatically controlled valve is used to circulate sufficient oil flow to the cooler to maintain temperature. From discussions with site personnel the system appears to function adequately. In February 2011, the system was assessed by Siemens who noted in their report that it generally appeared in good condition but recommended some reconditioning.

**Fire Protection System:** The fire system is an Ansul Inergen total-flooding type system that can operate automatically via fire detection or manually via pull stations. The system is comprised of Inergen storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers. It was installed in 2000 to replace the Halon fire system in respect of the ozone depleting substance regulations.

**Compressed Air & Nitrogen System:** The compressed air system consists of a single 600 volt motor/compressor unit, a 310 L (82 gallon) storage tank, a Pall instrument air dryer, and a small control and monitoring panel. The system is designed to supply 700 kPa instrument air to operate the power turbine snow doors, the main generator exhaust and intake louvers, and the jet engine intake and exhaust cooling air louvers. It also has provisions for a four-bottle nitrogen back-up supply in the event of a compressor system failure. The control panel provides pressure indication for the system and a transfer valve to the nitrogen supply.

**Diesel Generators:** The Stage 1 and Stage 2 Diesel Generators and auxiliaries are not located within the GT building and are not part of the scope of this study. Nevertheless, they are critical to the operation of the GT units and are discussed briefly here. Two diesel units located within the main generating facility provide 600 V power for blackstart operation and start of the existing GT. They are anticipated to be required for any replacement black start generator as well.

Both diesel gensets are designed for controlled safe shutdown of the units. They have the necessary auxiliaries to be stand-alone – controls, switchgear, cooling, and lubrication.

The Stage 1 diesel was replaced in the last five years, and the Stage 2 diesel is currently planned to be replaced in 2015.



FIGURE 2-4 LIGHT OIL RECEIVING & LUBE OIL RADIATOR



EXHAUST STACK



AIR INTAKE

FIGURE 2-5 GTG EXHAUST STACK & AIR INTAKE

### 2.3.2 Major Maintenance History

The following is a summary of significant work completed since 2003. No major overhauls have been completed on the entire machine.

**16 October 2003**

- Intake plenum contained debris, chipped floor and flaking paint. Recommended clean up.

**10 August 2004**

- Air plenum cleaner than 2003 visit, holes still visible in walls.

**27 September 2005**

- Annual inspection and boroscope inspection;
- Corrosion/ Rust found in Plenum; and
- Hot gas leakage at Exhaust Transition duct to power turbine.

**13 March 2006**

- Leak in each end of the gearbox at the bearing seals. (Caused fire when oil leaked into insulation around PT and dripped onto top of tank). Greenray discovered turbine shaft/seal modifications, recommended machining and reconditioning.

**13 April 2006**

- None

**25 May 2007**

- Rebuild of the intake with securing bolts torque and locked; and
- Replace/ Repair exhaust snow doors.

**21 May 2008**

- Package filtration inspection;
- Plenum survey;
- Fuel/oil system: connection, fuel pump/ oil pump, pipelines, oil level & quality, filter and basket removal (replacement consumables); and
- On engine review: bleed valves, IGV ram (filter review), gearbox inspection (filters, speed pick up, consumable change), fuel control unit review, oil cooler, fuel filter change, burner removal (ultrasonic cleaning), fuel rail inspection, drain valve operation, thermocouple inspection (terminal cleaning), transition inspection, removal of insulation, rectify leaks, inspect LP blades.

**10 June 2008**

- Water pooling noted in intake plenum along with holes in structure and loose debris.

**15 October 2009**

- Exhaust stack needs replacement, lower components noted in good condition. Door opening components to be serviced; and
- Transition duct piston rings seals to be replaced.

**20 November 2009**

- Commissioning;

- Exhaust transition lagging replaced due to fuel saturation; and
- Split air manifold cracks, to be repaired.

**2011**

NL Hydro undertook a number of activities with vendors that have the OEM rights in order to conduct detailed internal inspections of the individual sections and prepare field inspection reports complete with refurbishment estimates.

- Rolls Wood Group has the OEM rights to the front end bearing assembly, compressor rotor, compressor casings, combustion assembly, nozzle casing, rear bearing housing, turbine assembly, exhaust unit, and accessories. They were recently contracted by NL Hydro to conduct detailed internal inspections of the above noted equipment and have prepared a field inspection report complete with refurbishment estimates.
- Braden Manufacturing is a company that specializes in the design and manufacturing of combustion turbine air filtration systems, air inlet systems, and exhaust systems. They were recently contracted by NL Hydro to perform detailed inspections of the GT air inlet plenum, air filtration system, air inlet plenum support structure, exhaust stack and exhaust stack support structure.

### 2.3.3 Condition Assessment & Remaining Life

**TABLE 2-17 CONDITION ASSESSMENT – GAS TURBINE BOP**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Fire System | Fire System | BOP1 | Fire system upgraded in 2000 to Ansul Inergen total-flooding type (automatic via fire detection or manually via pull stations). All of existing Inergen system (storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers) are in good condition. Detection and suppression system did not detect 2010 GT gearbox fires - likely require some improvements. | 4/10 | (30) | 10+ | 2020 | Yes | 2000 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Cooler/Radiator | Radiator | BOP2 | The cooler has experienced a substantial amount of surface corrosion due to the environment.Motor appears in good condition, but dirty. Corrosion has led to some tube leaks in 2010. Some ice freezing within containment area. Fan thermostatically controlled valve is working adequately. In February 2011 Siemens noted that the system appeared generally in good shape but recommended some reconditioning. | 4 | (20) | 3 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil System | Lube Oil | BOP3 | Overdue for overhaul. Gearbox lube oil seal leaks and subsequent fires have led to regulatory restriction on unit operation to emergency only. | 4 | (30) | 0 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Pumps | AC & DC pumps | BOP4 | Siemens indicated AC and DC lube oil pumps in good condition, but no internal inspection or vibration test practical. Plant experienced that lube oil delivery engine driven pump was not maintaining sufficient main pressure, requiring the AC pump to operate continuously. | 4/10 | (30) | 2 | 2020 | No | 1986 |
| 1297 | 7199 | 7205 | 0 | COMPRESSED AIR SYSTEMS | Compressed Air Systems | N/A | BOP5 | The single 600 volt motor/compressor unit, 310 L (82 gallon) storage tank, Pall instrument air dryer and small control and monitoring panel are fairly new and in good condition.The pressure vessels are inspected annually in accordance with government regulations. No indication of any significant degradation. | 4 | 30 | 10+ | 2020 | Yes | 2000 |
| 1297 | 7199 | 7205 | 7231 | COMPRESSED AIR SYSTEMS | Nitrogen(Compressed Air Back-up) System | N/A | BOP6 | The four-bottle nitrogen back-up supply (used in the event of a compressor system failure) and its control panel driven transfer valve are in good operable condition. No issues identified. | 4 | 30 | 10+ | 2020 | Yes | 2000 |

Notes: 1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

The current inspection and maintenance program for the diesels is reasonable and should suffice to allow the units to reach their normal end of life. If the existing level II generator replacement is delayed this will impact the reliability of the overall system to operate in black start.

The maintenance required on the AC lube oil cooler recommended by Siemens in the February 2011 report should be completed to ensure reliability.

Review of the information available on the fires on the existing GT does not mention any activation of the Inergen system. It was noted from inspection of the system in the turbine room that there appears to be only one discharge nozzle in which is located above the compressor section of the GT. This was later confirmed during a review of existing drawings. The fires occurred on the opposite side of the room behind the exhaust stack which would likely have reduced the effectiveness of the system in the event of a discharge. The three detectors in the room also appear to be heat detectors and not smoke which is possibly why the system did not react to the fires which have been described as a small amount of flame and smoke. These fires were extinguished by several portable units.

In general, the lube oil system is in poor shape and in need of refurbishment as part of the overhaul. The fire system, while relatively new and capable of lasting beyond 2020, requires modification for functionality reasons. The air compressor and nitrogen systems are relatively new and will last beyond 2020 with reasonable maintenance.

## 2.3.4 Risk Assessment

**TABLE 2-18 RISK ASSESSMENT – GAS TURBINE BOP**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Major Issues | Remaining Life Years | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Fire System | Fire System | BOP1 | Fire system upgraded in 2000 to Ansul Inergen total-flooding type (automatic via fire detection or manually via pull stations). All of existing Inergen system (storage containers, piping, nozzles, control panel, actuators, detection and alarm devices, and pressure relief dampers) are in good condition. Detection and suppression system did not detect 2010 GT gearbox fires - likely require some improvements. | Fire detection failure and suppression failure exists. | 10/0 | 4 | C | High | 3 | D | High | Failure to detect and suppress fire | Modify detection and suppression system. In GTG area cameras for external monitoring. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Cooler/Radiator | Radiator | BOP2 | The cooler has experienced a substantial amount of surface corrosion due to the environment.Motor appears in good condition, but dirty. Corrosion has led to some tube leaks in 2010. Some ice freezing within containment area. Fan thermostatically controlled valve is working adequately. In February 2011 Siemens noted that the system appeared generally in good shape but recommended some reconditioning. | Lube Oil cooler failure and leak - containment limits risk. Unit 8navailability. | 3 | 3 | B | Medium | 3 | A | Low | Tube failures. Unavailable due to ice freeze up. | Repair/replace with winter icing protection. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil System | Lube Oil | BOP3 | Overdue for overhaul. Gearbox lube oil seal leaks and subsequent fires have led to regulatory restriction on unit operation to emergency only. | Gearbox seal oil leaks exist and fires have occurred. | 0 | 4 | C | High | 4 | D | High | Fire | New seals; gearbox lube oil air vents; monitor. Improve fire detection and suppression. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Pumps | AC & DC pumps | BOP4 | Siemens indicated AC and DC lube oil pumps in good condition, but no internal inspection or vibration test practical. Plant experienced that lube oil delivery engine driven pump was not maintaining sufficient main pressure, requiring the AC pump to operate continuously. | Lube oil system AC pump overuse | 2 | 4 | B | Medium | 4 | A | Low | Pump failure (DC back-up and shutdown) | Repair |
| 1297 | 7199 | 7205 | 0 | COMPRESSED AIR SYSTEMS | Compressed Air Systems | N/A | BOP5 | The single 600 volt motor/compressor unit, 310 L (82 gallon) storage tank, Pall instrument air dryer and small control and monitoring panel are fairly new and in good condition.The pressure vessels are inspected annually in accordance with government regulations. No indication of any significant degradation. | None | 10+ | 1 | D | Low | 1 | A | Low | High pressure air storage failure. Winter stack doors don't open (N2 back-up) | Monitor |
| 1297 | 7199 | 7205 | 7231 | COMPRESSED AIR SYSTEMS | Nitrogen(Compressed Air Back-up) System | N/A | BOP6 | The four-bottle nitrogen back-up supply (used in the event of a compressor system failure) and its control panel driven transfer valve are in good operable condition. No issues identified. | None | 10+ | 1 | D | Low | 1 | A | Low | High pressure N2 storage failure. Winter stack doors don't open | Monitor |

## 2.3.5 Actions

**TABLE 2-19 ACTIONS – GAS TURBINE BOP**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Action Summ. ID# | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Fire System | Fire System | BOP1 | Modify fire detection and suppression system. Install GTG room cameras | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Cooler/Radiator | Radiator | BOP2 | Replace/Repair/refurbish and eliminate icing issues. If re-conditioned, stem clean motor and perform no load and vibration tests. | 2012 | 2 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil System | Lube Oil | BOP3 | New seals; gearbox lube oil air vents; monitor. Improve fire detection and suppression. | 2012 | 1 |
| 1273 | 7202 | 7311 | 99003602 | GAS TURBINE AUXILIARY SYSTEMS | LUBE OIL PUMPS | | BOP4 | Overhaul AC and DC motors (steam clean). Perform VPI test for insulation. Perform no load and vibration tests. Install anti-condensation heaters. | 2012 | 1 |
| 1297 | 7199 | 7205 | 0 | COMPRESSED AIR SYSTEMS | COMPRESSED AIR SYSTEMS | N/A | BOP5 | None - monitor | | |
| 1297 | 7199 | 7205 | 7231 | COMPRESSED AIR SYSTEMS | NITROGEN (COMPRESSOR BACK-UP) SYSTEM | N/A | BOP6 | None - monitor | | |

### 2.3.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The newer equipment and systems (compressed air, nitrogen) can all meet the 2020 end date with normal maintenance. The lube oil system requires refurbishment and with normal maintenance, should be able to meet the 2020 end date. The AC lube oil cooler fan is recommended to have the repairs recommended by Siemens to maximize the remaining life of the system or be replaced. It will then, with regular intervals of repair and maintenance, last to 2020.

The Stage 1 diesel, not a part of this assessment, but is relatively new and therefore expected to be operational until at least 2020. The Stage 2 diesel is original equipment, installed in 1979. It is at the end of its normal useful life.

### 2.3.7 Level 3 Inspections Required

No incremental to refurbishment Level 3 assessments are required.

### 2.3.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-20.

**TABLE 2-20 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE BOP**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Fire System | Fire System | BOP1 | Modification of detection and suppression system for better protection and coverage. New monioring camera system. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Cooler/Radiator | Radiator | BOP2 | New lube oil cooler | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil System | Lube Oil | BOP3 | New gear box seals, lube oil venting | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | Lube Oil Pumps | AC & DC pumps | BOP4 | No Captial Requirement | | |
| 1297 | 7199 | 7205 | 0 | COMPRESSED AIR SYSTEMS | Compressed Air Systems | N/A | BOP5 | No Captial Requirement | | |
| 1297 | 7199 | 7205 | 7231 | COMPRESSED AIR SYSTEMS | Nitrogen(Compressed Air Back-up) System | N/A | BOP6 | No Captial Requirement | | |

### 2.3.8.1 Capital Refurbishment Requirements and Costs

The Stage 2 diesel and its auxiliary systems should be replaced to achieve 2020.

The AC lube oil cooler fan requires refurbishment as recommended by Siemens.

Since there is a likelihood of a fire in the area near the exhaust stack and above the gearbox, it is recommended that additional nozzles be added to the turbine room above the gearbox near the stack, and under the turbine in the vicinity of the origin of the fires to ensure unobstructed effective dispersion of the Inergen gas. It is also recommended that the addition of infrared flame detectors be considered as thermal lag on fixed temperature detectors can delay the activation of the system as can a slowly developing fire on rate of rise detectors. The flame detector effectiveness will depend on the ambient heat radiation from the gas turbine which can decrease its effectiveness.

The suggested typical capital enhancements for the gas turbine BOP include:

**TABLE 2-21 CAPITAL COST –GAS TURBINE BOP**

**Capital cost estimate $ 1,000 Can 2011**

| BOP Systems | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Fuel enclosure (See Civil/Structural) | | | | |
| | Fuel piping | $60 | $15 | $75 | $60-$90 |
| | Stack removal | $0 | $30 | $30 | $25-$35 |
| | Inergen system | $7 | $3 | $10 | $7-$15 |
| | Lube oil cooler | $130 | $20 | $150 | $75-$175 |
| | **Sub-Total** | **$197** | **$68** | **$265** | **$150-$320** |
| 10% | **Contingency** | **$20** | **$7** | **$27** | |
| | **TOTAL BOP** | **$217** | **$75** | **$292** | **$180-$350** |

## 2.4 Gas Turbine/Fuel Oil Equipment/Processes

| | |
|---|---|
| Unit #: | Common |
| Asset Class # | BU 1297 - Assets Common |
| SCI & System: | 7199 HRD Common Systems |
| Sub-System | 7209 Light Oil System |
| Components: | To Be Added |
| | |
| | |

### 2.4.1 Description - Gas Turbine Generator Light Fuel Oil System

Light fuel oil (No.2 diesel) is delivered by truck to the unloading skid adjacent to the existing GT generator building. The single 600 volt off-loading pump with local start / stop control is located outdoors at the northwest corner of the gas turbine building and has above-ground piping connecting it to the bulk storage tanks. Power for the motor is supplied from the gas turbine MCC control centre. The two 100,000 litre above-ground fuel tanks were fabricated in 1998 to ULC-S601-93 standards with double wall construction and have a total storage capacity of 200,000 litres. The offloading system is comprised of a single 600 volt pump arrangement with local start / stop control. Power for the motor is supplied from the GT MCC control centre.

The piping installation is typical with a 3 inch Y strainer, isolation valves and piping to the storage tanks. Two 100%, 600 volt, centrifugal forwarding pumps provides low pressure No.2 diesel fuel for the jet engine. The fuel passes through a duplex suction strainer and a 5 micron discharge filter before reaching the jet engine. The fuel line also incorporates a fuel flow/totalizing meter and a fire system trip valve prior to entering the building.

Light oil (No.2 fuel oil) from the light oil fuel oil storage tanks is gravity fed. The light oil pressure at the main units is maintained through constant recirculation back to the light oil storage tanks through a pressure control valve and piping arrangement.

The existing fuel supply system to the GT, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the GT building and is exposed to a harsh marine environment and as a result, has heavy surface corrosion.

The fuel lines in the dike area are in better condition likely as a result of being at least partially protected from the elements.

Some fuel forwarding pumps are located in a small enclosure to protect them from the elements. The concrete containment system in which the pumps sit was filled with approximately 4 inches of oily water at the time of the inspection.





**FIGURE 2-6 LIGHT OIL RECEIVING SYSTEM AND STORAGE TANKS**

### 2.4.2 Major Maintenance History

**Light Oil Storage Tanks & Receiving System:** The light oil storage tanks are approximately 13 years old. Aside from the issue that the interstitial pressure was outside its normal design levels, we are not aware of any major maintenance items on these tanks. Inspection information was not considered given the relatively short duration since their in-service date. They are subject to API regulatory inspection.

**Pipelines:** The lines under the roadway have been replaced as part of road repair work carried out in 2007.



### 2.4.3 Condition Assessment & Remaining Life

The condition assessment of the fuel systems (light oil) is illustrated below in Table 2-22.

**TABLE 2-22 CONDITION ASSESSMENT – GAS TURBINE FUEL OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | LIGHT FUEL OIL SYSTEM | | | | | | | | | |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GENERAL | General | LFO1 | Exposed receiving and delivery system componets corroded. Build-ups of snow and ice freeze up in containment areas common. | 4 | (40) | (2) | 2020 | No | 1986 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | PIPING | N/A | LFO2 | Significant external corrosion and pitting.due to the marine environment, including the lines to the light oil storage tanks. Recent ultrasonic testing (Oct 2010) indicates that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.significant weather that may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | 4 | (40) | (2) | 2020 | No | 1986 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GT TRANSFER PUMPS AND FILTERS | N/A | LFO3 | The fuel pumps and filters are located in small enclosures are not readily accessible. Siemens indicated that motors appear in fair condition with some surface corrosion. Conduit appeared in good condition. A full assessment was not possible due to accessibility. The enclosures still fill somewhat with water and snow. The concrete containment system in which the pumps sit was filled approximately 4" with oily water at the time of the visit. THis may freeze in winter and snow makes them less accessible during the winter which may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | 4 | (40) | (2) | 2020 | No | 1986 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | FUEL RECEIVING/FORWARDING PUMPS | N/A | LFO4 | The fuel receiving/transfer pumps, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the Gas Turbine Building and exposed to a harsh marine environment and have heavy surface corrosion as a result. Snow and ice in winter makes them less accessible and may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | 4 | (40) | (2) | 2020 | No | 1986 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | General | LFO5 | Relatively new, about 13 years. No inspections that station are aware of. | 3a | (40) | 10+ | 2020 | Yes | 1998 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO6 | Interstitial vacuum pressure on both tanks are -35 and -38 mm Hg. Very faded warning stickers on the tanks indicated if the vacuum pressure was less than – 42 mm Hg the manufacturer should be contacted. While the gauges still indicate a high vacuum in each tank, there is a concern tahta Holyrood management acknowledged this as an ongoing issue with the tanks that they were aware of. | 3a | (40) | 10+ | 2020 | Yes | 1998 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO7 | Fuel oil tank penetrations on the top of the tank are showing heavy corrosion. No other data available. | 3a | (40) | 10+ | 2020 | Yes | 1998 |

Notes: 1. A "(bracketed)" value in the "Current Expected Remaining Life" column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as "(X/Y)" has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

A review of the 2006 SGE Acres report "Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and dike Drainage System Holyrood Thermal Generating Station" was used to determine the existing condition of the tanks in conjunction with a walkthrough of the tank farm. During examination of the two light oil tanks, it was noted that the interstitial vacuum pressure on both tanks are -35 and -38 mm HG . Very faded warning stickers on the tanks indicated if the vacuum pressure was less than 42 mm hg the manufacture should be contacted. While the gauges still indicate a high vacuum in each tank, the concern was brought forward to Holyrood management and was acknowledged as an ongoing issue with the tanks that they were aware of.

It was also noted that the fuel oil tank penetrations on the top of the tank are showing heavy corrosion. Since these tanks are critical to the operation of diesel gensets, the black start gas turbine, and main unit ignition it is recommended that this corrosion be addressed through regular maintenance.

The light oil receiving, pumping and piping system located at the gas turbine building is operational, but have experienced significant external corrosion due to the marine environment, including the lines to the light oil storage tanks and to the powerhouse ignition oil system. Some data was made available on ultrasonic testing of the lines from October 2010, it appears from preliminary review of the results that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.

The piping exterior is in poor condition due to its prolonged exposure to the marine environment. Extreme weather may prevent emergency repairs on the exposed fuel equipment during a black start event. Given their exposure to the harsh marine environment, the existing fuel supply system to the gas turbine, the fire alarm fuel shut off valve, and the fuel offloading system located adjacent to the G Building is not expected to continue to 2020. While the majority of the components are fairly standard and off the shelf, a failure of the Gas Turbine fuel system during black start would be costly both financially and in terms of time.

## 2.4.4 Risk Assessment

**TABLE 2-23 RISK ASSESSMENT – GAS TURBINE FUEL OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Major Issues | Remaining Life Years | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Likeli-hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | LIGHT FUEL OIL SYSTEM | | | | | | | | | | | | | |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GENERAL | General | LFO1 | Exposed receiving and delivery system componets corroded. Build-ups of snow and ice freeze up in containment areas common. | Oil Leak; failure to operate and access easily. | (2) | 3 | A | Low | 4 | A | Medium | Modest oil spill within containment; inability to start unit until ice cleared | Install new fuel receing/handling shed |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | PIPING | N/A | LFO2 | Significant external corrosion and pitting.due to the marine environment, including the lines to the light oil storage tanks. Recent ultrasonic testing (Oct 2010) indicates that the piping is within acceptable wall thickness tolerances despite the external corrosion at the moment. The fuel pumps located in the small enclosures are not readily accessible and would be less so during the winter.significant weather that may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | Oil Leak; failure to operate and access easily. | (2) | 3 | A | Low | 4 | A | Medium | Modest oil spill within containment; inability to start unit until ice cleared | Install new fuel receing/handling shed |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GT TRANSFER PUMPS AND FILTERS | N/A | LFO3 | The fuel pumps and filters are located in small enclosures are not readily accessible. The enclosures still fill somewhat with water and snow. The concrete containment system in which the pumps sit was filled approximately 4" with oily water at the time of the visit. THis may freeze in winter and snow makes them less accessible during the winter which may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | Oil Leak; failure to operate and access easily. | (2) | 3 | A | Low | 4 | A | Medium | Modest oil spill within containment; inability to start unit until ice cleared | Install new fuel receing/handling shed |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | FUEL RECEIVING/FORWARDING PUMPS | N/A | LFO4 | The fuel receiving/transfer pumps, fire alarm fuel shut off valve, and fuel offloading system are located adjacent to the Gas Turbine Building and exposed to a harsh marine environment and have heavy surface corrosion as a result. Snow and ice in winter makes them less accessible and may prevent emergency repairs on the exposed fuel equipment in the event of a black start requirement. | Oil Leak; failure to operate and access easily. | (2) | 3 | A | Low | 4 | A | Medium | Modest oil spill within containment; inability to start unit until ice cleared | Install new fuel receing/handling shed |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | General | LFO5 | Relatively new, about 13 years. No inspections that station are aware of. | Regulatory out of complince. | 10+ | 2 | A | Low | 2 | B | Medium | Ensure regulatoy inspection compliance undertaken. | Tank inspection. |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO6 | Interstitial vacuum pressure on both tanks are -35 and -38 mm Hg. Very faded warning stickers on the tanks indicated if the vacuum pressure was less than – 42 mm Hg the manufacturer should be contacted. While the gauges still indicate a high vacuum in each tank, there is a concern tahta Holyrood management acknowledged this as an ongoing issue with the tanks that they were aware of. | Operating outside vendor recommended limits. Leak.. | 10+ | 3 | A | Low | 2 | B | Medium | Modest oil spill within containment; inability to start unit until ice cleared | Investigate rezson and repair. Replace warning stickers. |

## 2.4.5 Actions

**TABLE 2-24 ACTIONS – GAS TURBINE FUEL OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Action Summ. ID# | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | LIGHT FUEL OIL SYSTEM | | | | | |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GENERAL | General | LFO1 | | | |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | PIPING | N/A | LFO2 | Replace fuel piping downstream of filters with stainless. Refurbsih remaining piping, vales etc. Enclose building related equipment in fuel shed. | 2012 | 2 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GT TRANSFER PUMPS AND FILTERS | N/A | LFO3 | Replace fuel receiving and transfer piping. Enclose in fuel shed. | 2012 | 1 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | FUEL RECEIVING/FORWARDING PUMPS | N/A | LFO4 | Replace fuel receiving and transfer piping. Enclose in fuel shed. | 2012 | 1 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | General | LFO5 | | | |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO6 | Inspect per regulatory and maintain | 2012 | 1 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO7 | Investigate interstial vacuum difference and repair. Replace warning stickers. | 2012 | 2 |

### 2.4.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/Replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The system should be capable of meeting the 2020 end date with reasonable maintenance. Modifications including stainless steel piping from filters to the GT, and the installation of a fuel shed and replacement of system to address winter weather impacts. The issue is primarily problems resulting from extreme weather impacts and less with the equipment itself. The oil storage tanks should with maintenance and regulatory inspection make the 2020 end date.

### 2.4.7 Level 3 Inspections Required

Given the condition historical data reviewed and recommended changes, no Level 3 analyses are necessary.

### 2.4.8 Capital Enhancements

The suggested capital projects for the GT E&C systems are presented in Table 2-25.

**TABLE 2-25 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE FUEL OIL SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1273 | 7202 | 7311 | 0 | GAS TURBINE AUXILIARY SYSTEMS | LIGHT FUEL OIL SYSTEM | | | | | |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GENERAL | General | LFO1 | New fuel shed. | 2012 | 1 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | PIPING | N/A | LFO2 | New stainless steel piping from filters to GTG | 2012 | 1 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | GT TRANSFER PUMPS AND FILTERS | N/A | LFO3 | New system | 2012 | 1 |
| 1297 | 7199 | 7209 | 0 | LIGHT OIL SYSTEM | FUEL RECEIVING/FORWARDING PUMPS | N/A | LFO4 | New system | 2012 | 1 |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | General | LFO5 | No Captial Requirement | | |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO6 | No Captial Requirement | | |
| 1297 | 7199 | 7209 | 99034713 | LIGHT OIL SYSTEM | OIL STORAGE TANK | N/A | LFO7 | No Captial Requirement | | |

### 2.4.9 Capital/Refurbishment and Overhaul Costs (Capital)

It is recommended that the fuel system, fire alarm fuel shut off valve and fuel offloading system be refurbished/replaced and be enclosed in a full sized shelter. This will help protect the exposed equipment and allow for safe operation and repairs unhindered by weather and enclosures too small to work in.

The suggested equipment and installation costs (refurbishment of existing equipment) for the system are presented in Table 2-26.

**TABLE 2-26 CAPITAL COST ESTIMATE – GAS TURBINE FUEL OIL SYSTEM**

| Item | Cost |
|---|---|
| Fuel enclosure | $40,000 |
| Fuel piping | $75,000 |
| Stack removal | $ 30,000 |
| Inergen system | $10,000 |
| Lube oil cooler | $150,000 |

## 2.5 Building and Structural/Civil Equipment

| | |
|---|---|
| Unit #: | COMMON |
| Asset Class # | BU 1297 – Assets Common |
| SCI & System: | 7255 HRD Buildings & Site |
| Sub-Systems: | 272255 HRD Buildings |
| Components: | 7307 HRD Gas Turbine Building |
| Sub-Components: | 7307 HRD Gas Turbine Building |

### 2.5.1 Description

The GT building at the plant houses the GT that is used in the event of a black start. The existing gas turbine building was constructed in 1986. The building is of pre-engineered, galvanized metal-panel construction, 40 ft in width and 50 ft in length with R20 exterior wall insulation. The foundation is of conventional reinforced concrete pier/wall and floor slab construction and incorporates the original turbine and module slabs. A full height concrete block partition wall was installed to completely separate the turbine/generator sections from the remaining building area. It houses a one tonne hoist/track provision to move equipment to the service area. The electrical area is divided into a battery room, a control room and an MCC/switchgear section. It has an oil drain provision for both the service and turbine rooms complete with a reinforced concrete trap. A rolling service door between the turbine and work area is provided for fire containment but easily removed for heavy equipment.

#### 2.5.1.1 Gas Turbine Building Asbestos

Pinchin Leblanc undertook an “Asbestos Materials Re-Assessment” study of Holyrood for NL Hydro in 2010 (Pinchin Leblanc Project 02-02-004-01, November 19, 2010).

The study was not exhaustive and rather a review of areas identified previously, some of which had been addressed. It did not appear to address the GT building specifically, but did indicate that the metal sheet siding of some of the out buildings on the site were made of a material called Galbestos which had a backing of non-friable tarpaper containing chrysotile asbestos. The study indicated that this siding material should be repaired or removed following Type 1 (low risk) asbestos abatement procedures.

Given that the GT building was installed at the Holyrood site in 1986, it is unlikely that the siding material was Galbestos. Nevertheless, before any modification work is undertaken on the siding or other building components, the presence or absence of asbestos should be verified.

No cost or time has been allowed for asbestos evaluation or removal in this assessment, as the likelihood of its presence is low and the risk associated with its removal is identified by the report as being low.

### 2.5.2 Major Maintenance History

No inspection records specific to the turbine building were identified. A visual walkthrough of the gas turbine building was performed to gauge the existing condition of the building.

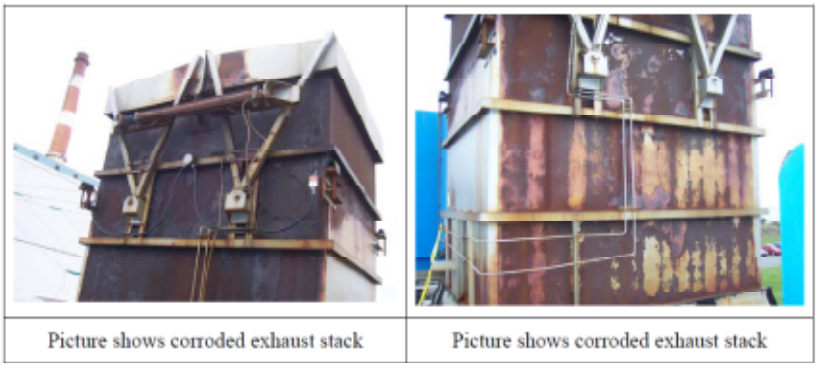
**Structural:** The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members located below the exhaust stack that sits on the roof of the building over the turbine.

**Roofs & Siding:** The siding and roof of the gas turbine building, specifically in the area around the stack, at the roofliner, and at the base of the building, show evidence of significant corrosion.

**Exhaust Stack:** The exhaust stack is extensively corroded with leaks into the building and into the turbine, and should be replaced.



| Picture shows corroded exhaust stack | Picture shows corroded exhaust stack |
|---|---|



| Picture shows corroded exhaust stack | Picture shows corroded exhaust stack |
|---|---|

**FIGURE 2-7 CORRODED EXHAUST STACK (GAS TURBINE PLANT**

### 2.5.3 Condition Assessment & Remaining Life

The condition assessment of the buildings and building M and E system is illustrated below in Table 2-27.

**TABLE 2-27 CONDITION ASSESSMENT – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Status Identifier | Original Life (Base Load) Ops Hrs (Yrs) | Current Expected Minimum Remaining Life Years (Subject to Test) | End of Life (EOL) Required | Capability to Reach EOL | In Service |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7307 | BUILDINGS | GAS TURBINE BUILDING | N/A | BLDG1 | Generally in good condition with modest corrosion and no significant structural deficiencies noted, except where related to gas turbine intake and exhaust. Some surface corrosion on structural members located below the exhaust stack. Sidings and roofs of the Gas Turbine Building have some corrosion requiring repair. | 4 | (40) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Structure - General | Structure | BLDG2 | The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members in the turbine room located immediately below the exhaust stack that sits on the roof of the building over the turbine. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Service Room: | Service Room: | BLDG3 | Visible structural steel in service room is in excellent condition with paint covering the members and no signs of corrosion or major structural deficiencies. The masonry wall dividing the service room and turbine room is in excellent condition on this side. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Turbine Room | Turbine Room | BLDG4 | Structural steel is in good condition except in the immediate vicinity of the exhaust stack. The steel members in this area have moderate corrosion owing to water infiltration around the stack. The masonry wall dividing the service room and turbine room is in excellent condition on this side. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Generator Room | Generator Room | BLDG5 | Visible structural steel in generator room is in good condition except in the immediate vicinity of the exhaust stack. Steel members directly surrounding the exhaust ducting has minor corrosion owing to water infiltration at the roof. This evidenced by rust running down the side of the ducting. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Battery Room /MCC Room /Control Room | Battery Room | BLDG6 | These rooms have their own infill structure that is covered by finishes. There does not appear to be any structural deficiencies in these areas. The building structural steel above these rooms is somewhat visible from the Service Room and looks to be in the same good condition as the steel in that room. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Roofing | Roofing | BLDG7 | The roof of the gas turbine building, specifically in the area around the stack, at the roof liner, shows evidence of moderate corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams) | 4/10 | (20) | 10/1 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Siding | Siding | BLDG8 | The siding of the gas turbine building, specifically at the base of the building, show evidence of significant corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams) | 4/10 | (20) | 10/1 | 2020 | No | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Hoists / Lifting | Hoists / Lifting | BLDG9 | There is a main monorail which spans between the Service Room and Turbine Room. This monorail is excellent condition with no signs of corrosion or structural deficiencies. There are two minor lifting beams between the power generator and power turbine. These monorails are in good condition with only minor surface corrosion and no major structural deficiencies. There is a monorail in the generator room which is in excellent conditions with no signs of corrosion or structural deficiencies. | 4/10 | (20) | 10+ | 2020 | Yes | 1986 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Exhaust Stack Structure | Exhaust Stack Structure | BLDG10 | The steel support frame is good condition with only moderate corrosion, with paint covering the majority of the frame surface and no sign of major structural deficiencies. The structural frame holding up the exhaust cannot be assessed visually as it rests above the main structure obscured from view inside and above the roofline it is covered in flashing. The lifting lugs are in good condition with no signs of major corrosion. The sealant used to weather proof the connection of the frame to the roof is cracking and it should be assumed the frame exhibits similar corrosion as the primary structural steel inside. While not technically a structural item, the exhaust stack itself is extensively corroded above the roof line allowing water to leak into the building causing corrosion. | 4/10 | (20) | 10/0 | 2020 | No | 1986 |

Notes: 1. A “(bracketed)” value in the “Current Expected Remaining Life” column is a highly probable minimum value that is considered subject to some subsequent verification during further investigation, including at the next test or overhaul. It may be addressed as part of a Level 2 test. A value identified as “(X/Y)” has been included for the steam turbine and generator where the recommended minimum value is the lower of the two, but that the higher may be achievable at a higher level of failure risk and/or unreliability.

## 2.5.4 Risk Assessment

**TABLE 2-28 RISK ASSESSMENT – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Condition | Major Issues | Remaining Life Years | TECHNO-ECO RISK ASSESS MODEL | | | SAFETY RISK ASSESS MODEL | | | Possible Failure Event | Mitigation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | (Insufficient Info - Inspection Required Within (x) Years) | Likeli--hood | Conse-quence | Risk Level | Likeli-hood | Conse-quence | Safety Risk | | |
| 1297 | 7255 | 272255 | 7307 | BUILDINGS | GAS TURBINE BUILDING | | | | | | | | | | | | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Structure - General | Structure | BLDG1 | The structural systems that comprise the building are in excellent condition with very little corrosion found and no major structural deficiencies noted. There was significant surface corrosion found on the structural members in the turbine room located immediately below the exhaust stack that sits on the roof of the building over the turbine. | Stack leaks causing structural member surface corrosion. | 10+ | 1 | B | Low | 1 | C | Medium | Structural steel member sigifican corrosion. Stack support failure. | Monitor. Replace/repair leaks in area of stack and check support. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Service Room: | Service Room | BLDG2 | Visible structural steel in service room is in excellent condition with paint covering the members and no signs of corrosion or major structural deficiencies. The masonry wall dividing the service room and turbine room is in excellent condition on this side. | None | 10+ | 1 | A | Low | A | B | LOW | None expected. | Monitor |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Turbine Room | Turbine Room | BLDG3 | Structural steel is in good condition except in the immediate vicinity of the exhaust stack. The steel members in this area have moderate corrosion owing to water infiltration around the stack. The masonry wall dividing the service room and turbine room is in excellent condition on this side. | Stack support failure 9eventual). | 10+ | 3 | B | Medium | 1 | C | Medium | Structural steel member sigifican corrosion. Stack support failure. | Monitor. Replace/repair leaks in area of stack and check support. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Generator Room | Generator Room | BLDG4 | Visible structural steel in generator room is in good condition except in the immediate vicinity of the exhaust stack. Steel members directly surrounding the exhaust ducting has minor corrosion owing to water infiltration at the roof. This evidenced by rust running down the side of the ducting. | Stack support failure 9eventual). | 10+ | 3 | B | Medium | 1 | C | Medium | Structural steel member sigifican corrosion. Stack support failure. | Monitor. Replace/repair leaks in area of stack and check support. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Battery Room /MCC Room /Control Room | Battery Room | BLDG5 | These rooms have their own infill structure that is covered by finishes. There does not appear to be any structural deficiencies in these areas. The building structural steel above these rooms is somewhat visible from the Service Room and looks to be in the same good condition as the steel in that room. MCC Requirements require more space. | Regulatory compliance re MCC's and other electrical equipment spacing. | 1-Oct | 3 | B | Medium | 3 | C | Medium | Electrtical equipment failure in limited space. Regulatory non-compliance. | Increase space when replacing MCC's and/or other electrical room equipment. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Roofing | Roofing | BLDG6 | The roof of the gas turbine building, specifically in the area around the stack, at the roof liner, shows evidence of moderate corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams) | Roof failure. Water damage in gas turbine causing major damage. | 10/1 | 4 | C | High | 3 | C | Medium | Power turbine water in-leakage causing failure. Stack support failure. | Replace/repair leaks in area of stack and check support. Replace stack. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Siding | Siding | BLDG7 | The siding of the gas turbine building, specifically at the base of the building, show evidence of significant corrosion. Unless these areas are repaired there is a risk the deterioration might accelerate and begin to affect the primary structural members. (ie. columns, beams) | Inleakage of marine salt laden air causing increased corrosion. | 10/1 | 4 | A | Medium | 4 | a | Medium | Structural steel member sigifican corrosion. Stack support failure. | Repair existing holes and sections. Check for asbestos. |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Hoists / Lifting | Hoists / Lifting | BLDG8 | There is a main monorail which spans between the Service Room and Turbine Room. This monorail is excellent condition with no signs of corrosion or structural deficiencies. There are two minor lifting beams between the power generator and power turbine. These monorails are in good condition with only minor surface corrosion and no major structural deficiencies. There is a monorail in the generator room which is in excellent conditions with no signs of corrosion or structural deficiencies. | None | 10+ | 1 | C | Low | 1 | C | LOW | Failure during GT part lift. | Monitor |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Exhaust Stack Structure | Exhaust Stack Structure | BLDG9 | The steel support frame is good condition with only moderate corrosion, with paint covering the majority of the frame surface and no sign of major structural deficiencies. The structural frame holding up the exhaust cannot be assessed visually as it rests above the main structure obscured from view inside and above the roofline it is covered in flashing. The lifting lugs are in good condition with no signs of major corrosion. The sealant used to weather proof the connection of the frame to the roof is cracking and it should be assumed the frame exhibits similar corrosion as the primary structural steel inside. While not technically a structural item, the exhaust stack itself is extensively corroded above the roof line allowing water to leak into the building causing corrosion. | Water inleakage into power turbine and gearbox area. | 10/0 | 4 | C | High | 3 | C | Medium | Power turbine failure. Stack support failure. | Replace stack and repair roof leaks. |

### 2.5.5 Actions

TABLE 2-29 ACTIONS – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Action Summ. ID# | Action | Year | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7307 | BUILDINGS | GAS TURBINE BUILDING | N/A | BLDG1 | Generally repair areas of moisture penetration and air leaks. | 2012 | 2 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Structure - General | Structure | BLDG2 | Maintain and monitor | 2012 | 2 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Service Room: | Service Room: | BLDG3 | Maintain and monitor | 2012 | 4 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Turbine Room | Turbine Room | BLDG4 | Fix roof near stack and stack | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Generator Room | Generator Room | BLDG5 | Fix roof near stack and stack | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Battery Room /MCC Room /Control Room | Battery Room & MCC Room /Control Room | BLDG6 | Expand room per current codes when replacing equipment | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Roofing | Roofing | BLDG7 | Repair roofing around stack. Inspect and maintain balance. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Siding | Siding | BLDG8 | Repair current corrosion areas | 2012 | 2 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Hoists / Lifting | Hoists / Lifting | BLDG9 | None - Inspect and monitor ongoing | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Exhaust Stack Structure | Exhaust Stack Structure | BLDG10 | Fix roof near stack and stack | 2012 | 1 |

### 2.5.6 Life Assessment - Life Cycle Curves (Where Equipment Is Not To Be Overhauled/replaced and Life <2020 and Has Major Unit Operation Impacts)

No Life Cycle Curves are presented. The building with the recommended modifications and repairs can all meet the 2020 end date.

### 2.5.7 Level 3 Inspections Required

A higher level of inspection is required to confirm the lifting capability of the existing expansion joint / skid which exhaust fan is framed into. It was not confirmed if the existing building contains asbestos. If the roof is disturbed to service/replace the exhaust duct testing should be completed to determine if there is any asbestos in the roofing materials.

Removal of small sections of interior paneling and insulation in areas where corrosion exists in the turbine and power generator rooms should be carried out determine the condition of steel columns in areas where exterior siding has corroded through. These are considered outside of the scope of this assessment and part of the GT overhaul or facility asbestos program,

### 2.5.8 Capital Enhancements

The suggested capital projects for the GT building and building M and E systems are presented in Table 2-30.

**TABLE 2-30 SUGGESTED TYPICAL CAPITAL ENHANCEMENTS – GAS TURBINE BUILDINGS AND BUILDING M AND E SYSTEM**

| BU # 1 | Asset # 2 | Asset # 3 | Asset # 4 | Asset Level 3 | Description | Detail | Cond. Summ. ID# | Capital Item | Date | Priority |
|---|---|---|---|---|---|---|---|---|---|---|
| 1297 | 7255 | 272255 | 7307 | BUILDINGS | GAS TURBINE BUILDING | N/A | BLDG1 | Expansion of building for electrical system requirements and for fuel oil shed. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Structure - General | Structure | BLDG2 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Service Room: | Service Room: | BLDG3 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Turbine Room | Turbine Room | BLDG4 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Generator Room | Generator Room | BLDG5 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Battery Room /MCC Room /Control Room | Battery Room /MCC Room /Control Room | BLDG6 | Expansion of building for electrical system requirements. | 2012 | 1 |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Roofing | Roofing | BLDG7 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Siding | Siding | BLDG8 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Hoists / Lifting | Hoists / Lifting | BLDG9 | No Captial Requirement | | |
| 1273 | 7202 | 7311 | 0 | GAS TURBINE BUILDING | Exhaust Stack Structure | Exhaust Stack Structure | BLDG10 | New stack | 2012 | 1 |

### 2.5.9 Capital/Refurbishment Requirements and Costs

The following are the requirements for the complete refurbishment of the building:

- Repair sections of roofing and siding that are corroded and allowing water infiltration. Cost = Approximately $5,000;
- The addition of a building extension to shelter the turbine fuel line mechanical equipment from the elements, likely single span pre-engineered lean-to. Cost = Approximately $40,000;
- Addition of electrical building Cost = Approximately $40,000

## 2.6 Existing Unit De-Commissioning and Demolition in 2020

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as a sensitivity, then a value such as $40,000 (2011$) might be used, but this would not be expected to either sway the selection of a preferred option, nor impact the overall cost but rather be part of an overall project contingency regardless of any option selected.

## 2.7 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. NL Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals. It may be necessary to maintain a schedule for NL Hydro to either procure a power turbine disk or at least a manufacturing slot for the materials and manufacturing pending an EPC which would be free-issued the same (with some guarantee provision exclusions likely).

**EPC Costs**

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be about 8% of direct costs. The project management and commissioning costs (excluding fuel, NL Hydro staff costs) are estimated to be 8% of direct costs.

**Owner's Costs**

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that the Owner costs could amount to in the order of 1.5% of directs or about $150,000.

## 2.8 Existing GTG Refurbishment - Total Cost Estimate

The total existing GT refurbishment cost estimate is shown in Table 2-31. Details are provided in Appendix 7.

**TABLE 2-31 EXISTING GTG REFURBISHMENT COST ESTIMATE**

**Capital cost estimate $1,000 Can 2011**

| **Option Number** | **0** |
|---|---|
| **Option** | **Existing GT Refurb** |
| GT/Diesel Cost | $2,950 |
| Civil Works | $224 |
| Electrical Works | $541 |
| BOP Systems | $330 |
| Existing Unit Demolition & Removal | $0 |
| **Sub-Total - Directs and Indirects** | $4,046 |
| Project Engineering | $324 |
| Project Management | $283 |
| Total | $4,652 |

| | |
|---|---|
| + Standby = Total | $4,825 |
| | |
| + New Rental Stdby = Total | $9,421 |

Owner's costs were not included, but are expected to be in the order of about 1.5% of direct and indirect cost, plus any taxes and interest where applicable. It should be noted that it may be possible to obtain a used power turbine disk and refurbish it, as opposed to buying a new disk. This may slightly reduce the overall cost slightly. The availability of other parts is considered to be relatively good, but uncertain until a formal tender is issued.

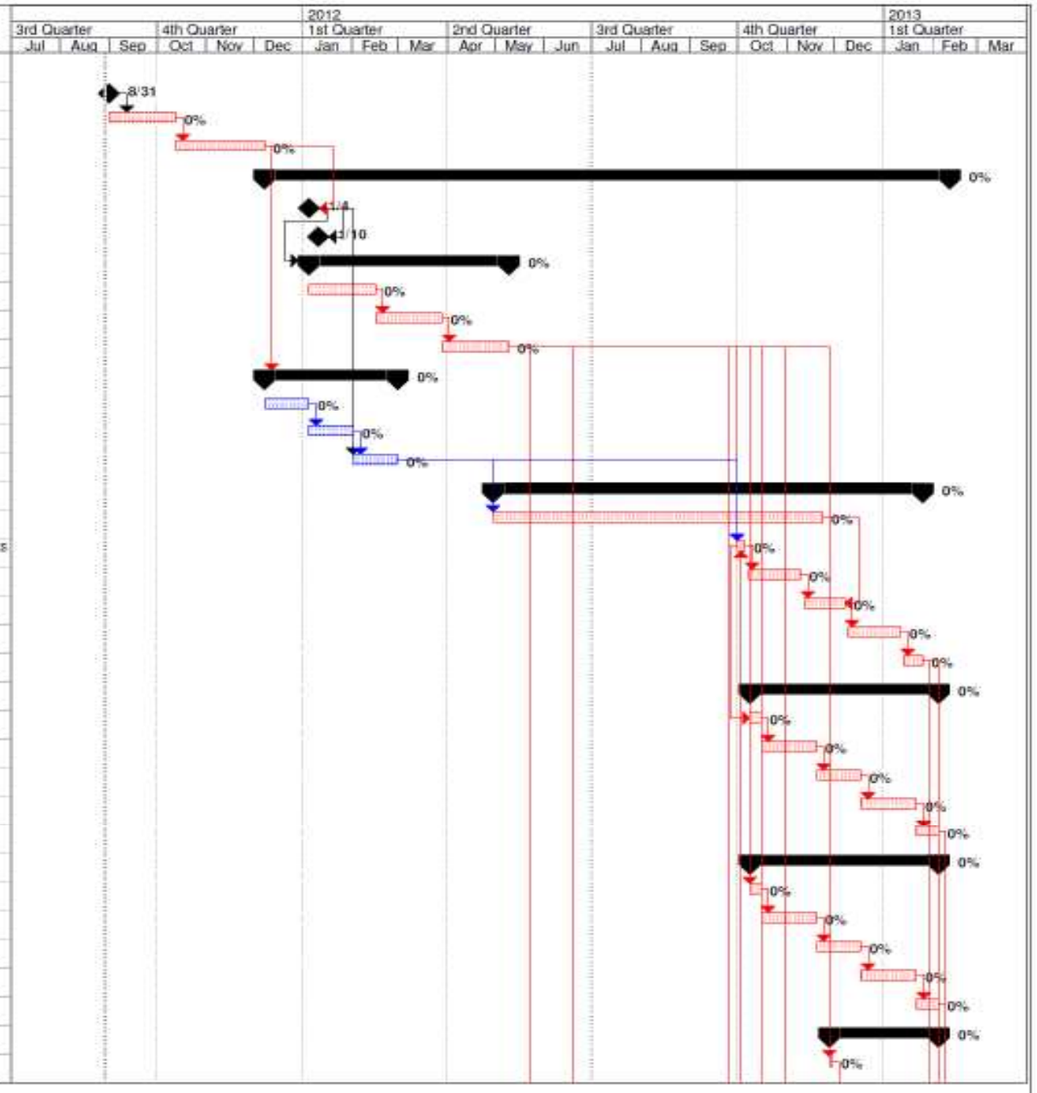
### 2.8.1 Schedule

The basic "earliest return to service" schedule for the existing GTG unit refurbishment is shown in Figure 2-8 below. Its in-service date is in February 2013. It assumes no replacement unit in six month outage window from September 2012 to February 2013. It is based on an EPC RFP, with the exception of the procurement of a Power Turbine disk which is then free-issued to the EPC contractor.

The outage occurs when Holyrood is normally required to operate. It is likely that the schedule would be allowed to slip to an in-service date in Oct 2013 to have the outage in April to Oct 2013.

**FIGURE 2-8 EXISTING GTG REFURBISHMENT – BASE SCHEDULE (NO OUTAGE REPLACEMENT CAPACITY)**

| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 | ish No Earlier Than | |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 | s Soon As Possible | 2 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 | s Soon As Possible | 3 |
| 5 | **Refurbish Unit** | **308 days** | **Thu 12/8/11** | **Mon 2/11/13** | **Soon As Possible** | |
| 6 | Project Limited Notice to proceed (LNTP) Approval | 0 days | Wed 1/4/12 | Wed 1/4/12 | s Soon As Possible | 4FF+4 wks |
| 7 | Project Full Notice to proceed (NTP) | 0 days | Tue 1/10/12 | Tue 1/10/12 | s Soon As Possible | 6FF+4 days |
| 8 | **Request for Proposal (RFP) - Engineer Procure Cor** | **90 days** | **Thu 1/5/12** | **Wed 5/9/12** | **Soon As Possible** | **6** |
| 9 | Prepare | 30 days | Thu 1/5/12 | Wed 2/15/12 | s Soon As Possible | |
| 10 | Bid | 30 days | Thu 2/16/12 | Wed 3/28/12 | s Soon As Possible | 9 |
| 11 | Award | 30 days | Thu 3/29/12 | Wed 5/9/12 | s Soon As Possible | 10 |
| 12 | **RFP for Power Turbine Disc Manufacture** | **60 days** | **Thu 12/8/11** | **Wed 2/29/12** | **Soon As Possible** | **4** |
| 13 | Prepare | 20 days | Thu 12/8/11 | Wed 1/4/12 | s Soon As Possible | |
| 14 | Bid | 20 days | Thu 1/5/12 | Wed 2/1/12 | s Soon As Possible | 13 |
| 15 | Award | 20 days | Thu 2/2/12 | Wed 2/29/12 | s Soon As Possible | 14,6 |
| 16 | **Power Turbine** | **195 days** | **Mon 4/30/12** | **Fri 1/25/13** | **Soon As Possible** | |
| 17 | Manufacture Disc | 30 wks | Mon 4/30/12 | Fri 11/23/12 | As Late As Possible | 15 |
| 18 | Strip and dissassemble plant | 1 wk | Mon 10/1/12 | Fri 10/5/12 | s Soon As Possible | 15,42,11FS+2 wks |
| 19 | Ship Rotor to overhaul plant | 5 wks | Mon 10/8/12 | Fri 11/9/12 | s Soon As Possible | 18 |
| 20 | Overhaul and balance Rotor | 4 wks | Mon 11/12/12 | Fri 12/7/12 | s Soon As Possible | 17FF+2 wks,19 |
| 21 | Ship Rotor to Holyrood | 5 wks | Mon 12/10/12 | Fri 1/11/13 | s Soon As Possible | 20 |
| 22 | Rebuild and commission unit | 2 wks | Mon 1/14/13 | Fri 1/25/13 | s Soon As Possible | 21 |
| 23 | **Gear Box Overhaul** | **85 days** | **Tue 10/9/12** | **Mon 2/4/13** | **Soon As Possible** | |
| 24 | Strip and dissassemble plant | 1 wk | Tue 10/9/12 | Mon 10/15/12 | As Late As Possible | 18SS |
| 25 | Ship to overhaul plant | 5 wks | Tue 10/16/12 | Mon 11/19/12 | As Late As Possible | 24 |
| 26 | Overhaul and balance Rotor | 4 wks | Tue 11/20/12 | Mon 12/17/12 | As Late As Possible | 25 |
| 27 | Ship to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | s Soon As Possible | 26 |
| 28 | Rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | s Soon As Possible | 27 |
| 29 | **Avon Gas Generator Overhaul** | **85 days** | **Tue 10/9/12** | **Mon 2/4/13** | **Soon As Possible** | |
| 30 | Strip and dissassemble plant | 1 wk | Tue 10/9/12 | Mon 10/15/12 | As Late As Possible | 11FS+2 wks |
| 31 | Ship Rotor to overhaul plant | 5 wks | Tue 10/16/12 | Mon 11/19/12 | As Late As Possible | 30 |
| 32 | Overhaul and balance Rotor | 4 wks | Tue 11/20/12 | Mon 12/17/12 | As Late As Possible | 31 |
| 33 | Ship Rotor to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | s Soon As Possible | 32 |
| 34 | Rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | s Soon As Possible | 33 |
| 35 | **Generator Rewind** | **49 days** | **Wed 11/28/12** | **Mon 2/4/13** | **Soon As Possible** | |
| 36 | Strip and dissassemble plant | 2 days | Wed 11/28/12 | Thu 11/29/12 | As Late As Possible | 11FS+2 wks |

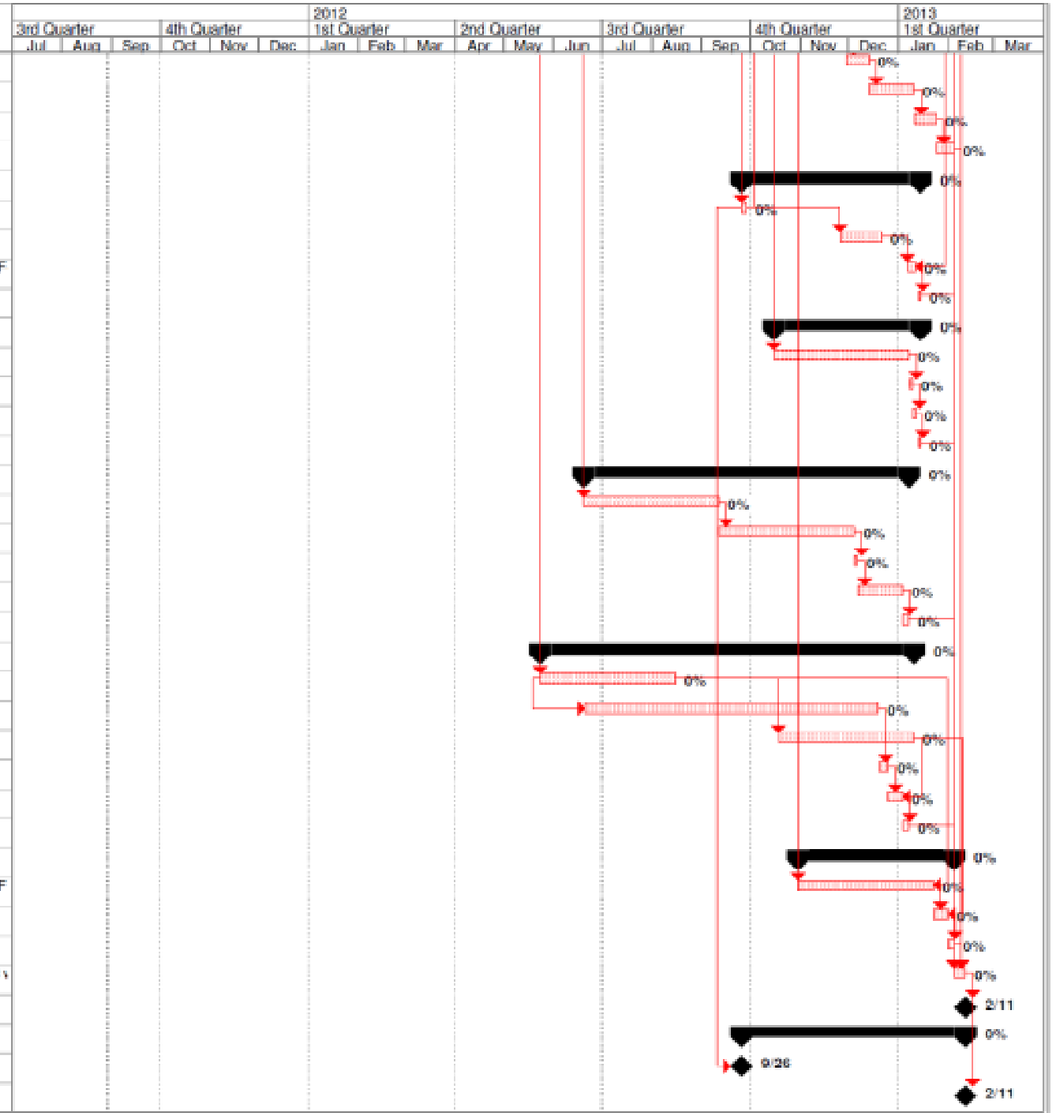



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Critical, Critical Split, Critical Progress, Task, Split, Task Progress, Baseline, Baseline Split, Baseline Milestone, Milestone, Summary Progress, Summary, Project Summary, External Tasks, External Milestone, Deadline

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| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 37 | Ship Rotor to overhaul plant | 2 wks | Fri 11/30/12 | Thu 12/13/12 | As Late As Possible | 36 |
| 38 | Overhaul, rewind, and balance Rotor | 4 wks | Fri 12/14/12 | Thu 1/10/13 | As Late As Possible | 37 |
| 39 | Ship Rotor to Holyrood | 2 wks | Fri 1/11/13 | Thu 1/24/13 | As Soon As Possible | 38 |
| 40 | Rebuild and commission unit | 7 days | Fri 1/25/13 | Mon 2/4/13 | As Soon As Possible | 39 |
| 41 | **Exhaust Stack** | **79 days** | **Wed 9/26/12** | **Mon 1/14/13** | **Soon As Possible** | |
| 42 | Remove | 3 days | Wed 9/26/12 | Fri 9/28/12 | As Late As Possible | 11FS+2 wks |
| 43 | Repair/Replace | 4 wks | Mon 11/26/12 | Fri 12/21/12 | As Late As Possible | 42 |
| 44 | Re-install | 5 days | Mon 1/7/13 | Fri 1/11/13 | As Late As Possible | 43FS+2 wks,22FF |
| 45 | Commission unit | 1 day | Mon 1/14/13 | Mon 1/14/13 | As Soon As Possible | 44 |
| 46 | **Intake media** | **65 days** | **Tue 10/16/12** | **Mon 1/14/13** | **Soon As Possible** | |
| 47 | Order & Manufacture Filter media | 12 wks | Tue 10/16/12 | Mon 1/7/13 | As Late As Possible | 11FS+2 wks |
| 48 | Remove | 2 days | Tue 1/8/13 | Wed 1/9/13 | As Late As Possible | 47 |
| 49 | Repair/Replace | 2 days | Thu 1/10/13 | Fri 1/11/13 | As Late As Possible | 48 |
| 50 | Commission unit | 1 day | Mon 1/14/13 | Mon 1/14/13 | As Soon As Possible | 49 |
| 51 | **Fuel System Refurbishments** | **144 days** | **Wed 6/20/12** | **Mon 1/7/13** | **Soon As Possible** | |
| 52 | Engineer | 12 wks | Wed 6/20/12 | Tue 9/11/12 | As Late As Possible | 11FS+2 wks |
| 53 | Order, Manufacture, Deliver | 12 wks | Wed 9/12/12 | Tue 12/4/12 | As Late As Possible | 52 |
| 54 | Remove | 2 days | Wed 12/5/12 | Thu 12/6/12 | As Late As Possible | 53 |
| 55 | Repair/Replace | 4 wks | Fri 12/7/12 | Thu 1/3/13 | As Late As Possible | 54 |
| 56 | Commission unit | 2 days | Fri 1/4/13 | Mon 1/7/13 | As Soon As Possible | 55 |
| 57 | **Electrical & Control Systmes** | **166 days** | **Thu 5/24/12** | **Thu 1/10/13** | **Soon As Possible** | |
| 58 | Engineer | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Late As Possible | 11FS+2 wks |
| 59 | Order & Manufacture Elect & Control Equip | 26 wks | Thu 8/21/12 | Wed 12/19/12 | As Late As Possible | 58SS+4 wks |
| 60 | GT Building Addition | 12 wks | Fri 10/19/12 | Thu 1/10/13 | As Late As Possible | 58 |
| 61 | Remove Existing | 4 days | Thu 12/20/12 | Tue 12/25/12 | As Late As Possible | 59 |
| 62 | Install New System | 7 days | Wed 12/26/12 | Thu 1/3/13 | As Late As Possible | 61,60FF-1 wk |
| 63 | Commission unit | 2 days | Fri 1/4/13 | Mon 1/7/13 | As Soon As Possible | 62 |
| 64 | **Building & Systmes** | **69 days** | **Wed 10/31/12** | **Mon 2/4/13** | **Soon As Possible** | |
| 65 | Engineer | 12 wks | Wed 10/31/12 | Tue 1/22/13 | As Late As Possible | 11FS+2 wks,58FF |
| 66 | Modify and Refurbish | 7 days | Wed 1/23/13 | Thu 1/31/13 | As Late As Possible | 65,60FF |
| 67 | Commission unit | 2 days | Fri 2/1/13 | Mon 2/4/13 | As Soon As Possible | 66 |
| 68 | Complete Unit Test | 5 days | Tue 2/5/13 | Mon 2/11/13 | As Soon As Possible | 34,40,22,45FS+3 v |
| 69 | Gas Turbine (GT) In-service (I/S) | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible | 68 |
| 70 | **UNIT OUTAGE** | **99 days** | **Wed 9/26/12** | **Mon 2/11/13** | **Soon As Possible** | |
| 71 | Unit Outage Start | 0 days | Wed 9/26/12 | Wed 9/26/12 | As Soon As Possible | 42SS |
| 72 | Unit Outage End | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible | 68 |




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Date: Mon 8/29/11

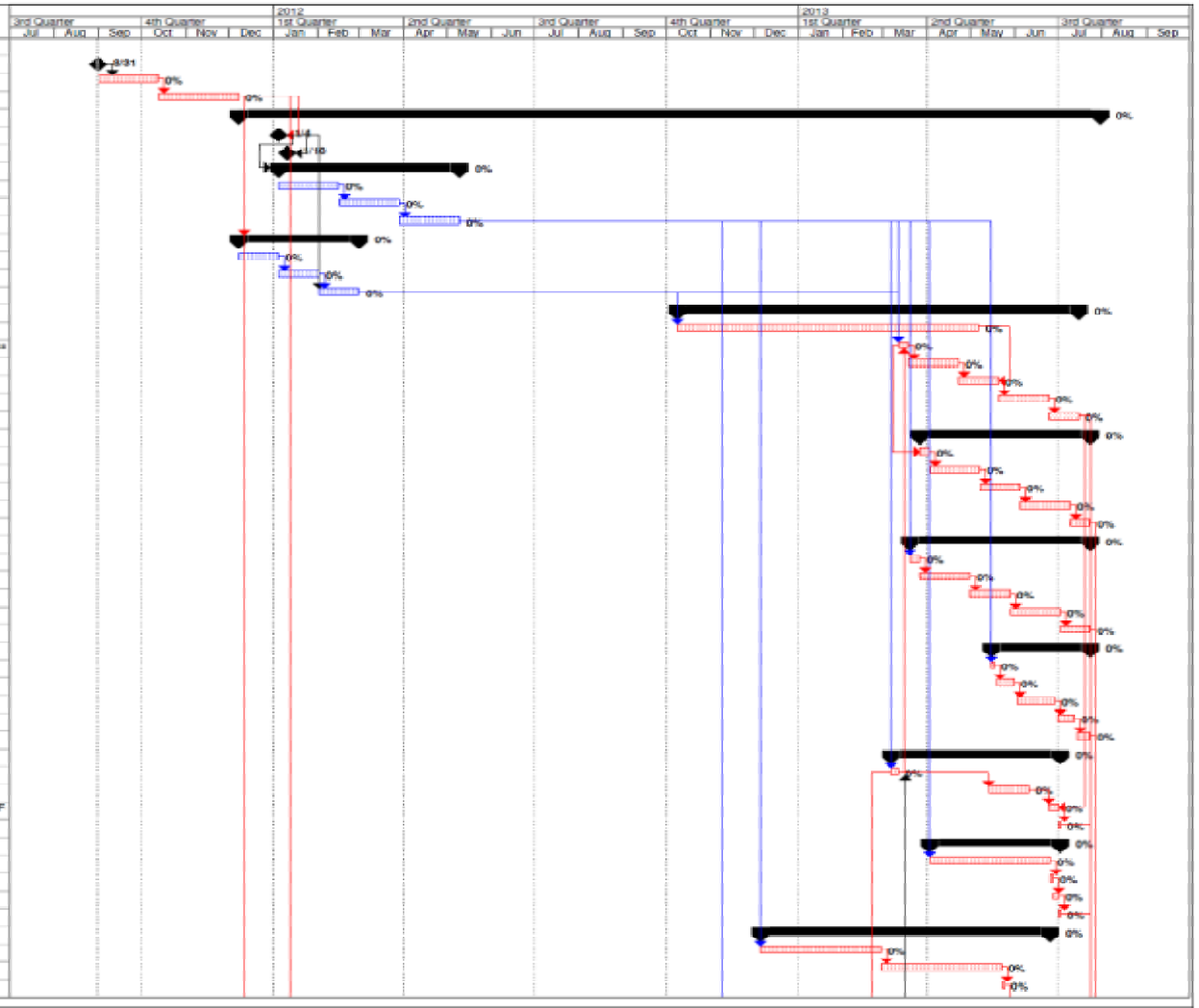
Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

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Figure 2-9 presents a variation of the basic "earliest return to service" schedule for the existing GTG unit refurbishment. It includes a replacement nearly new 2 x 5 MW GT during the outage window of the existing unit. The nearly new units would be in-service in March 2013. The resulting existing unit in-service date is end of July 2013, with a five month existing unit outage window from March to July 2013. It also is based on an EPC RFP, with the exception of the procurement of a Power Turbine disk which is free-issued to the EPC contractor. There is no significant period when black start capability is not available. A new 2 x 5MW unit would increase the schedule by about two months.

**FIGURE 2-9 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 1 (NEARLY NEW 2 X 5 MW GT REPLACEMENT DURING OUTAGE)**

| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 | Finish No Earlier Than | |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 | As Soon As Possible | 2 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 | As Soon As Possible | 3 |
| 5 | **Refurbish Unit** | **439 days** | **Thu 12/8/11** | **Tue 7/30/13** | **As Soon As Possible** | |
| 6 | Project Limited Notice to proceed (LNTP) Approval | 0 days | Wed 1/4/12 | Wed 1/4/12 | As Soon As Possible | 4FF+4 wks |
| 7 | Project Full Notice to proceed (NTP) | 0 days | Tue 1/10/12 | Tue 1/10/12 | As Soon As Possible | 6FF+4 days |
| 8 | **Request for Proposal (RFP) - Engineer/Procure/Cor** | **90 days** | **Thu 1/5/12** | **Wed 5/9/12** | **As Soon As Possible** | **6** |
| 9 | Prepare | 30 days | Thu 1/5/12 | Wed 2/15/12 | As Soon As Possible | |
| 10 | Bid | 30 days | Thu 2/16/12 | Wed 3/28/12 | As Soon As Possible | 9 |
| 11 | Award | 30 days | Thu 3/29/12 | Wed 5/9/12 | As Soon As Possible | 10 |
| 12 | **RFP for Power Turbine Disc Manufacture** | **60 days** | **Thu 12/8/11** | **Wed 2/29/12** | **As Soon As Possible** | **4** |
| 13 | Prepare | 30 days | Thu 12/8/11 | Wed 1/4/12 | As Soon As Possible | |
| 14 | Bid | 20 days | Thu 1/5/12 | Wed 2/1/12 | As Soon As Possible | 13 |
| 15 | Award | 20 days | Thu 2/2/12 | Wed 2/29/12 | As Soon As Possible | 14,6 |
| 16 | **Power Turbine** | **200 days** | **Tue 10/9/12** | **Mon 7/15/13** | **As Soon As Possible** | |
| 17 | Manufacture Disc | 30 wks | Tue 10/9/12 | Mon 5/6/13 | As Late As Possible | 15 |
| 18 | Strip and disassemble plant | 1 wk | Tue 3/12/13 | Mon 3/18/13 | As Late As Possible | 15,42,11FS-2 wks |
| 19 | Ship Rotor to overhaul plant | 5 wks | Tue 3/19/13 | Mon 4/22/13 | As Late As Possible | 18 |
| 20 | Overhaul and balance Rotor | 4 wks | Tue 4/23/13 | Mon 5/20/13 | As Late As Possible | 17FF+2 wks,19 |
| 21 | Ship Rotor to Holyrood | 5 wks | Tue 5/21/13 | Mon 6/24/13 | As Soon As Possible | 20 |
| 22 | Rebuild and commission unit | 3 wks | Tue 6/25/13 | Mon 7/15/13 | As Soon As Possible | 21 |
| 23 | **Gear Box Overhaul** | **85 days** | **Wed 3/27/13** | **Tue 7/23/13** | **As Soon As Possible** | |
| 24 | Strip and disassemble plant | 1 wk | Wed 3/27/13 | Tue 4/2/13 | As Late As Possible | 18SS |
| 25 | Ship to overhaul plant | 5 wks | Wed 4/3/13 | Tue 5/7/13 | As Late As Possible | 24 |
| 26 | Overhaul and balance Rotor | 4 wks | Wed 5/8/13 | Tue 6/4/13 | As Late As Possible | 25 |
| 27 | Ship to Holyrood | 5 wks | Wed 6/5/13 | Tue 7/9/13 | As Soon As Possible | 26 |
| 28 | Rebuild and commission unit | 2 wks | Wed 7/10/13 | Tue 7/23/13 | As Soon As Possible | 27 |
| 29 | **Avon Gas Generator Overhaul** | **90 days** | **Wed 3/20/13** | **Tue 7/23/13** | **As Soon As Possible** | |
| 30 | Strip and disassemble plant | 1 wk | Wed 3/20/13 | Tue 3/26/13 | As Late As Possible | 11FS+2 wks |
| 31 | Ship Rotor to overhaul plant | 5 wks | Wed 3/27/13 | Tue 4/30/13 | As Late As Possible | 30 |
| 32 | Overhaul and balance Rotor | 4 wks | Wed 5/1/13 | Tue 5/28/13 | As Late As Possible | 31 |
| 33 | Ship Rotor to Holyrood | 5 wks | Wed 5/29/13 | Tue 7/2/13 | As Soon As Possible | 32 |
| 34 | Rebuild and commission unit | 3 wks | Wed 7/3/13 | Tue 7/23/13 | As Soon As Possible | 33 |
| 35 | **Generator Rewind** | **49 days** | **Thu 5/16/13** | **Tue 7/23/13** | **As Soon As Possible** | |
| 36 | Strip and disassemble plant | 2 days | Thu 5/16/13 | Fri 5/17/13 | As Late As Possible | 11FS+2 wks |
| 37 | Ship Rotor to overhaul plant | 2 wks | Mon 5/20/13 | Fri 5/31/13 | As Late As Possible | 36 |
| 38 | Overhaul, rewind, and balance Rotor | 4 wks | Mon 6/3/13 | Fri 6/28/13 | As Late As Possible | 37 |
| 39 | Ship Rotor to Holyrood | 2 wks | Mon 7/1/19 | Fri 7/12/13 | As Soon As Possible | 38 |
| 40 | Rebuild and commission unit | 7 days | Mon 7/15/13 | Tue 7/23/13 | As Soon As Possible | 39 |
| 41 | **Exhaust Stack** | **84 days** | **Thu 3/7/13** | **Tue 7/2/13** | **As Soon As Possible** | |
| 42 | Remove | 3 days | Thu 3/7/13 | Mon 3/11/13 | As Late As Possible | 11FS-2 wks,108 |
| 43 | Repair/Replace | 4 wks | Tue 5/14/13 | Mon 6/10/13 | As Late As Possible | 42 |
| 44 | Re-Install | 5 days | Tue 6/25/13 | Mon 7/1/13 | As Late As Possible | 43FS+2 wks,22FF |
| 45 | Commission unit | 1 day | Tue 7/2/13 | Tue 7/2/13 | As Soon As Possible | 44 |
| 46 | **Intake media** | **65 days** | **Wed 4/3/13** | **Tue 7/2/13** | **As Soon As Possible** | |
| 47 | Order & Manufacture Filter media | 12 wks | Wed 4/3/13 | Tue 6/25/13 | As Late As Possible | 11FS-2 wks |
| 48 | Remove | 2 days | Wed 6/26/13 | Thu 6/27/13 | As Late As Possible | 47 |
| 49 | Repair/Replace | 2 days | Fri 6/28/13 | Mon 7/1/13 | As Late As Possible | 48 |
| 50 | Commission unit | 1 day | Tue 7/2/13 | Tue 7/2/13 | As Soon As Possible | 49 |
| 51 | **Fuel System Refurbishments** | **144 days** | **Thu 12/6/12** | **Tue 6/25/13** | **As Soon As Possible** | |
| 52 | Engineer | 12 wks | Thu 12/6/12 | Wed 2/27/13 | As Late As Possible | 11FS+2 wks |
| 53 | Order, Manufacture, Deliver | 13 wks | Thu 3/28/13 | Wed 6/26/13 | As Late As Possible | 52 |
| 54 | Remove | 2 days | Thu 5/23/13 | Fri 5/24/13 | As Late As Possible | 53 |

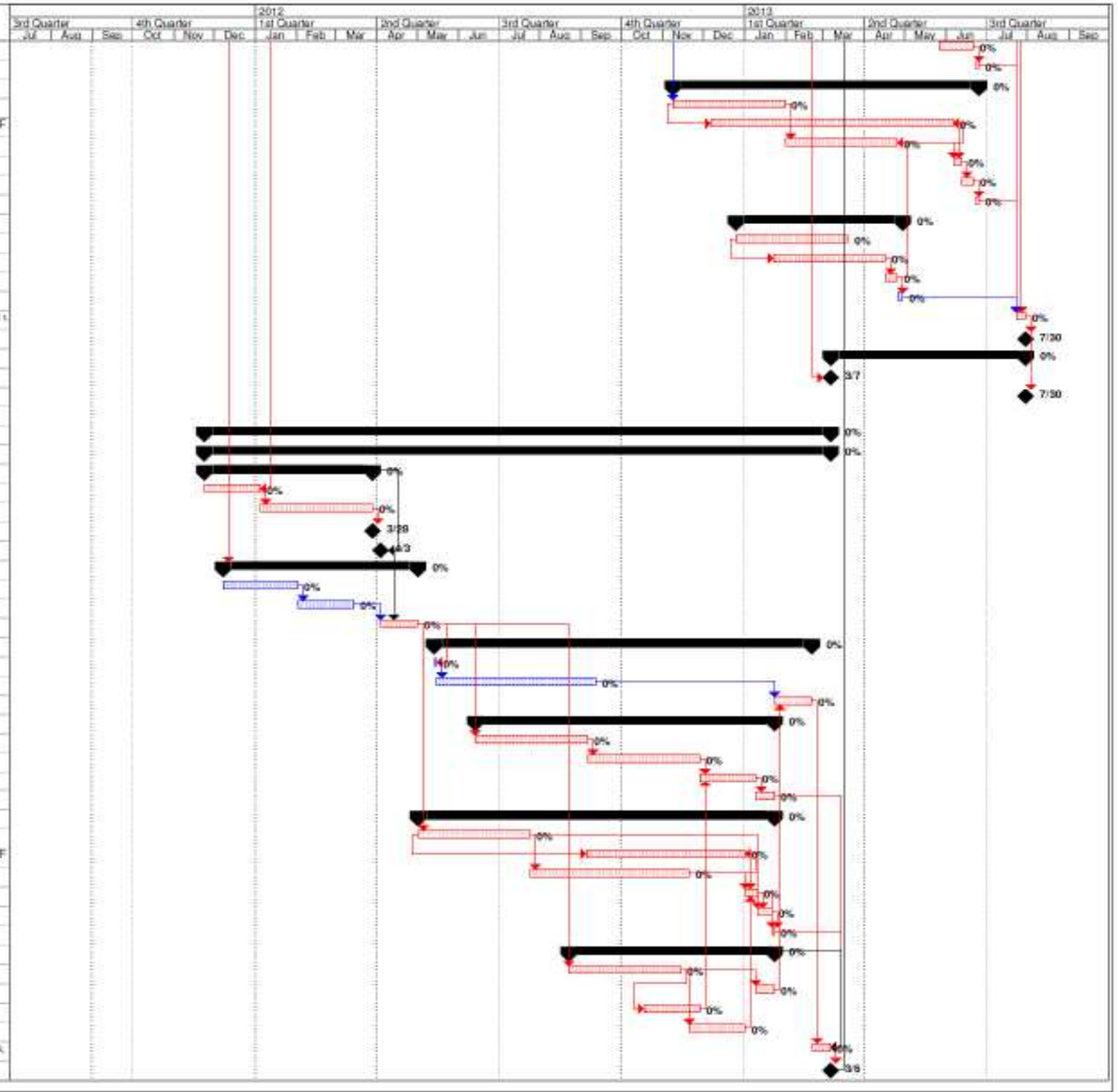



Project: Project1 Exist & Repla near re
Date: Wed 8/31/11

Critical | Critical Progress | Split | Baseline | Baseline Milestone | Summary Progress | Project Summary | External Milestone
Critical Split | Task | Task Progress | Baseline Split | Milestone | Summary | External Tasks | Deadline

Page 1

| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 55 | Repair/Replace | 4 wks | Mon 5/27/13 | Fri 6/21/13 | As Late As Possible | 54 |
| 56 | Commission unit | 2 days | Mon 6/24/13 | Tue 6/25/13 | As Soon As Possible | 55 |
| 57 | **Electrical & Control Systmes** | **163 days** | **Fri 11/9/12** | **Tue 6/25/13** | **As Soon As Possible** | |
| 58 | Engineer | 12 wks | Fri 11/9/12 | Thu 1/31/13 | As Late As Possible | 11FS+2 wks |
| 59 | Order & Manufacture Elect & Control Equip | 26 wks | Fri 12/7/12 | Thu 6/6/13 | As Late As Possible | 58SS+4 wks,60FF |
| 60 | GT Building Addition | 12 wks | Fri 2/1/13 | Thu 4/25/13 | As Late As Possible | 58,67FF |
| 61 | Remove Existing | 4 days | Fri 6/7/13 | Wed 6/12/13 | As Late As Possible | 60,59 |
| 62 | Install New System | 7 days | Thu 6/13/13 | Fri 6/21/13 | As Late As Possible | 61 |
| 63 | Commission unit | 2 days | Mon 6/24/13 | Tue 6/25/13 | As Soon As Possible | 62 |
| 64 | **Building & Systmes** | **89 days** | **Wed 12/26/12** | **Mon 4/29/13** | **As Soon As Possible** | |
| 65 | Engineer | 12 wks | Wed 12/26/12 | Tue 3/19/13 | As Late As Possible | |
| 66 | Order & Manufacture Elect & Control Equip | 12 wks | Wed 1/23/13 | Tue 4/16/13 | As Late As Possible | 65SS+4 wks |
| 67 | Modify and Refurbish | 7 days | Wed 4/17/13 | Thu 4/25/13 | As Late As Possible | 66 |
| 68 | Commission unit | 2 days | Fri 4/26/13 | Mon 4/29/13 | As Soon As Possible | 67 |
| 69 | Complete Unit Test | 5 days | Wed 7/24/13 | Tue 7/30/13 | As Soon As Possible | 34,40,22,45FS-3 |
| 70 | Gas Turbine (GT) In-service (I/S) | 0 days | Tue 7/30/13 | Tue 7/30/13 | As Soon As Possible | 69 |
| 71 | **UNIT OUTAGE** | **104 days** | **Thu 3/7/13** | **Tue 7/30/13** | **As Soon As Possible** | |
| 72 | Unit Outage Start | 0 days | Thu 3/7/13 | Thu 3/7/13 | As Soon As Possible | 42SS |
| 73 | Unit Outage End | 0 days | Tue 7/30/13 | Tue 7/30/13 | As Soon As Possible | 69 |
| 74 | | | | | | |
| 75 | **REPLACEMENT UNIT** | **335 days** | **Thu 11/24/11** | **Wed 3/6/13** | **As Soon As Possible** | |
| 76 | **Nearly New gas Turbine (GT) Generator Units** | **335 days** | **Thu 11/24/11** | **Wed 3/6/13** | **As Soon As Possible** | |
| 77 | **Project Environmental & Regulatory Approvals** | **90 days** | **Thu 11/24/11** | **Wed 3/28/12** | **As Soon As Possible** | |
| 78 | Prepare Dispersion Modelling & Submission | 30 days | Thu 11/24/11 | Wed 1/4/12 | As Soon As Possible | 4FF+4 wks |
| 79 | Regulatory Review and Approval | 60 days | Thu 1/5/12 | Wed 3/28/12 | As Soon As Possible | 78 |
| 80 | Environmental Approval | 0 days | Wed 3/28/12 | Wed 3/28/12 | As Soon As Possible | 79 |
| 81 | Project Full Release | 0 days | Tue 4/3/12 | Tue 4/3/12 | As Soon As Possible | 77FF+4 days |
| 82 | **Request for Proposal (RFP) for Engineer/Procu** | **104 days** | **Thu 12/8/11** | **Tue 5/1/12** | **As Soon As Possible** | **4** |
| 83 | Prepare | 40 days | Thu 12/8/11 | Wed 2/1/12 | As Soon As Possible | |
| 84 | Bid | 6 wks | Thu 2/2/12 | Wed 3/14/12 | As Soon As Possible | 83 |
| 85 | Award | 20 days | Wed 4/4/12 | Tue 5/1/12 | As Soon As Possible | 81,84 |
| 86 | **Nearly New GT or Diesel Engine Generator** | **203 days** | **Mon 5/14/12** | **Wed 2/20/13** | **As Soon As Possible** | |
| 87 | Award GT/Diesel Engine Contract | 2 days | Mon 5/14/12 | Tue 5/15/12 | As Soon As Possible | 85FF+10 days |
| 88 | Manufacture & Deliver Transportable Engine | 17 wks | Wed 5/16/12 | Tue 9/11/12 | As Soon As Possible | 87 |
| 89 | Install and Commission | 4 wks | Thu 1/24/13 | Wed 2/20/13 | As Soon As Possible | 88,104 |
| 90 | **Fuel System** | **160 days** | **Thu 6/14/12** | **Wed 1/23/13** | **As Soon As Possible** | |
| 91 | Engineer | 12 wks | Thu 6/14/12 | Wed 9/5/12 | As Late As Possible | 85 |
| 92 | Order, Manufacture, Deliver | 12 wks | Thu 9/6/12 | Wed 11/28/12 | As Late As Possible | 91 |
| 93 | Install new fuel lines and receiving system | 6 wks | Thu 11/29/12 | Wed 1/9/13 | As Late As Possible | 92,105 |
| 94 | Commission System | 2 wks | Thu 1/10/13 | Wed 1/23/13 | As Late As Possible | 93 |
| 95 | **Electrical & Control Systmes** | **191 days** | **Wed 5/2/12** | **Wed 1/23/13** | **As Soon As Possible** | |
| 96 | Engineer | 12 wks | Wed 5/2/12 | Tue 7/24/12 | As Late As Possible | 85 |
| 97 | Order & Manufacture Elect & Control (E&C) E | 17 wks | Wed 9/5/12 | Tue 1/1/13 | As Late As Possible | 96SS+4 wks,98FF |
| 98 | Electrical Building Manufacture, Delivery, Ins | 17 wks | Wed 7/25/12 | Tue 11/20/12 | As Late As Possible | 96 |
| 99 | Install New System | 7 days | Wed 1/2/13 | Thu 1/10/13 | As Late As Possible | 97,98,106 |
| 100 | RE-align Existing Plant Systems | 7 days | Fri 1/11/13 | Mon 1/21/13 | As Late As Possible | 96,99 |
| 101 | Commission unit | 2 days | Tue 1/22/13 | Wed 1/23/13 | As Soon As Possible | 99,100 |
| 102 | **Site Civil Work** | **110 days** | **Thu 8/23/12** | **Wed 1/23/13** | **As Soon As Possible** | |
| 103 | Engineer | 12 wks | Thu 8/23/12 | Wed 11/14/12 | As Late As Possible | 85 |
| 104 | Generator area clearing and civil | 2 wks | Thu 1/10/13 | Wed 1/23/13 | As Late As Possible | 103FS-6 wks |
| 105 | Fuel line civil work | 6 wks | Thu 10/18/12 | Wed 11/28/12 | As Late As Possible | 103FS-4 wks |
| 106 | Electrical an contro cable civil work | 6 wks | Wed 11/21/12 | Tue 1/1/13 | As Late As Possible | 103FS-2 wks |
| 107 | Complete Unit Test | 10 days | Thu 2/21/13 | Wed 3/6/13 | As Soon As Possible | 89,94FF+30 days, |
| 108 | GT In-Service (I/S) | 0 days | Wed 3/6/13 | Wed 3/6/13 | As Soon As Possible | 107 |




Project: Project1 Exist & Repls near ne
Date: Wed 8/31/11

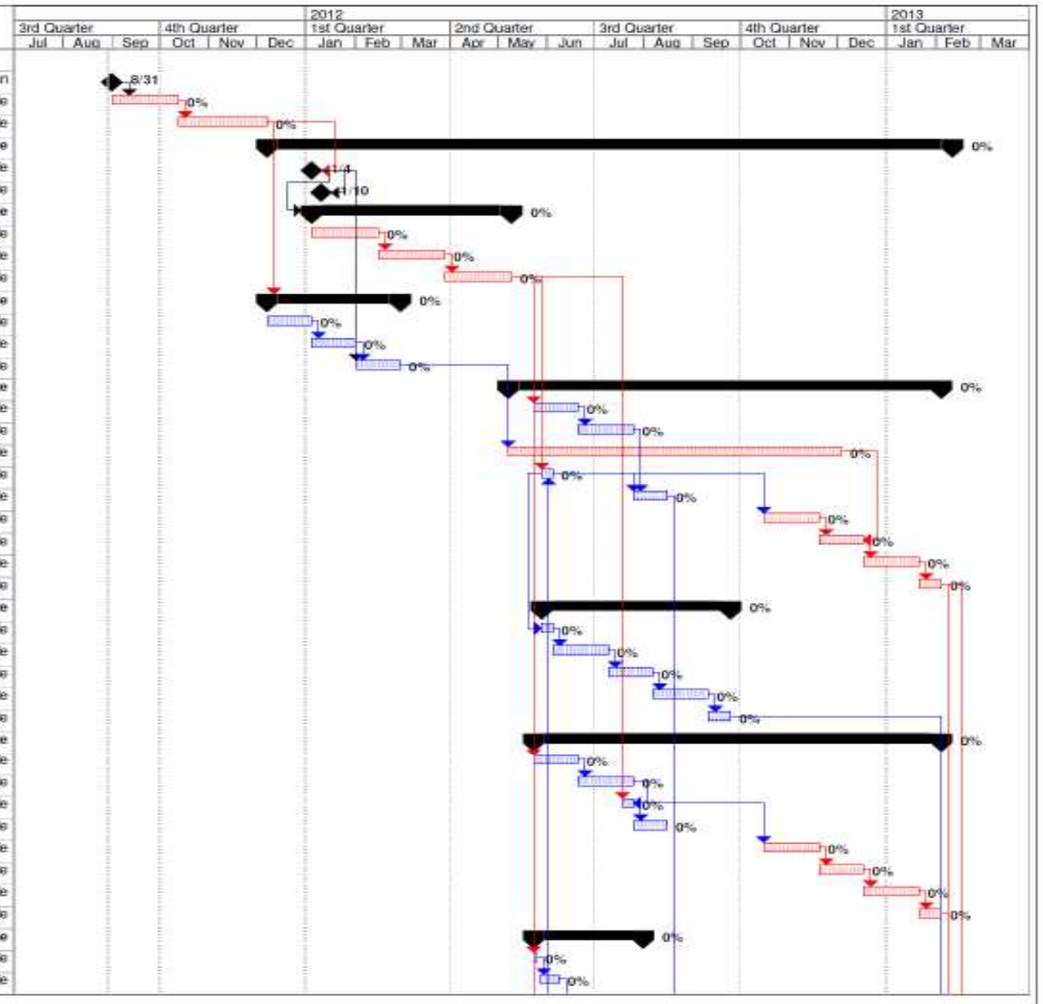
Critical | Critical Progress | Split | Baseline | Baseline Milestone | Summary Progress | Project Summary | External Milestone
Critical Split | Task | Task Progress | Baseline Split | Milestone | Summary | External Tasks | Deadline

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Figure 2-10 presents a second variation of the basic “earliest return to service” schedule for the existing GTG unit refurbishment. It assumes leased used replacements parts for the existing GT unit (the gas generator, the power turbine) to minimize the outage window, but does not. The in-service date is still February 2013, but with a longer outage window of 9 months from May 2012 to February 2013. The outage also occurs when Holyrood is normally required to operate, and given its duration would not be impacted by schedule shifting.

**FIGURE 2-10 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 2 (LEASED USED GAS GENERATOR AND POWER TURBINE DURING OUTAGE)**

| ID | Task Name | Duration | Start | Finish | Constraint Type |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 | Finish No Earlier Than |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 | As Soon As Possible |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 | As Soon As Possible |
| 5 | **Refurbish Unit** | **308 days** | **Thu 12/8/11** | **Mon 2/11/13** | **As Soon As Possible** |
| 6 | Project Limited Notice to proceed (LNTP) Approval | 0 days | Wed 1/4/12 | Wed 1/4/12 | As Soon As Possible |
| 7 | Project Full Notice to proceed (NTP) | 0 days | Tue 1/10/12 | Tue 1/10/12 | As Soon As Possible |
| 8 | **Request for Proposal (RFP) - Engineer/Procure/Construct (I** | **90 days** | **Thu 1/5/12** | **Wed 5/9/12** | **As Soon As Possible** |
| 9 | Prepare | 30 days | Thu 1/5/12 | Wed 2/15/12 | As Soon As Possible |
| 10 | Bid | 30 days | Thu 2/16/12 | Wed 3/28/12 | As Soon As Possible |
| 11 | Award | 30 days | Thu 3/29/12 | Wed 5/9/12 | As Soon As Possible |
| 12 | **RFP for Power Turbine Disc Manufacture** | **60 days** | **Thu 12/8/11** | **Wed 2/29/12** | **As Soon As Possible** |
| 13 | Prepare | 20 days | Thu 12/8/11 | Wed 1/4/12 | As Soon As Possible |
| 14 | Bid | 20 days | Thu 1/5/12 | Wed 2/1/12 | As Soon As Possible |
| 15 | Award | 20 days | Thu 2/2/12 | Wed 2/29/12 | As Soon As Possible |
| 16 | **Power Turbine** | **195 days** | **Tue 5/8/12** | **Mon 2/4/13** | **As Soon As Possible** |
| 17 | Procure Lease Disc and PT Assembly | 4 wks | Thu 5/24/12 | Wed 6/20/12 | As Soon As Possible |
| 18 | Refurbish PT Replacement | 5 wks | Thu 6/21/12 | Wed 7/25/12 | As Soon As Possible |
| 19 | Manufacture NEW PT Disc | 30 wks | Tue 5/8/12 | Mon 12/3/12 | As Late As Possible |
| 20 | Strip and dissassemble plant | 1 wk | Tue 5/29/12 | Mon 6/4/12 | As Soon As Possible |
| 21 | Rebuild and commission unit - Lease part | 3 wks | Thu 7/26/12 | Wed 8/15/12 | As Soon As Possible |
| 22 | Ship Rotor to overhaul plant | 5 wks | Tue 10/16/12 | Mon 11/19/12 | As Late As Possible |
| 23 | Overhaul and balance Rotor | 4 wks | Tue 11/20/12 | Mon 12/17/12 | As Late As Possible |
| 24 | Ship Rotor to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | As Soon As Possible |
| 25 | Replace lease part, rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | As Soon As Possible |
| 26 | **Gear Box Overhaul** | **85 days** | **Tue 5/29/12** | **Mon 9/24/12** | **As Soon As Possible** |
| 27 | Strip and dissassemble plant | 1 wk | Tue 5/29/12 | Mon 6/4/12 | As Soon As Possible |
| 28 | Ship to overhaul plant | 5 wks | Tue 6/5/12 | Mon 7/9/12 | As Soon As Possible |
| 29 | Overhaul and balance Rotor | 4 wks | Tue 7/10/12 | Mon 8/6/12 | As Soon As Possible |
| 30 | Ship to Holyrood | 5 wks | Tue 8/7/12 | Mon 9/10/12 | As Soon As Possible |
| 31 | Rebuild and commission unit | 2 wks | Tue 9/11/12 | Mon 9/24/12 | As Soon As Possible |
| 32 | **Avon Gas Generator Overhaul** | **183 days** | **Thu 5/24/12** | **Mon 2/4/13** | **As Soon As Possible** |
| 33 | Procure Lease Disc and PT Assembly | 4 wks | Thu 5/24/12 | Wed 6/20/12 | As Soon As Possible |
| 34 | Refurbish PT Replacement | 5 wks | Thu 6/21/12 | Wed 7/25/12 | As Soon As Possible |
| 35 | Strip and dissassemble plant | 1 wk | Thu 7/19/12 | Wed 7/25/12 | As Soon As Possible |
| 36 | Rebuild and commission unit - Lease part | 3 wks | Thu 7/26/12 | Wed 8/15/12 | As Soon As Possible |
| 37 | Ship Rotor to overhaul plant | 5 wks | Tue 10/16/12 | Mon 11/19/12 | As Late As Possible |
| 38 | Overhaul and balance Rotor | 4 wks | Tue 11/20/12 | Mon 12/17/12 | As Late As Possible |
| 39 | Ship Rotor to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | As Soon As Possible |
| 40 | Replace lease part, rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | As Soon As Possible |
| 41 | **Generator Rewind** | **49 days** | **Thu 5/24/12** | **Tue 7/31/12** | **As Soon As Possible** |
| 42 | Strip and dissassemble plant | 2 days | Thu 5/24/12 | Fri 5/25/12 | As Soon As Possible |
| 43 | Ship Rotor to overhaul plant | 2 wks | Mon 5/28/12 | Fri 6/8/12 | As Soon As Possible |

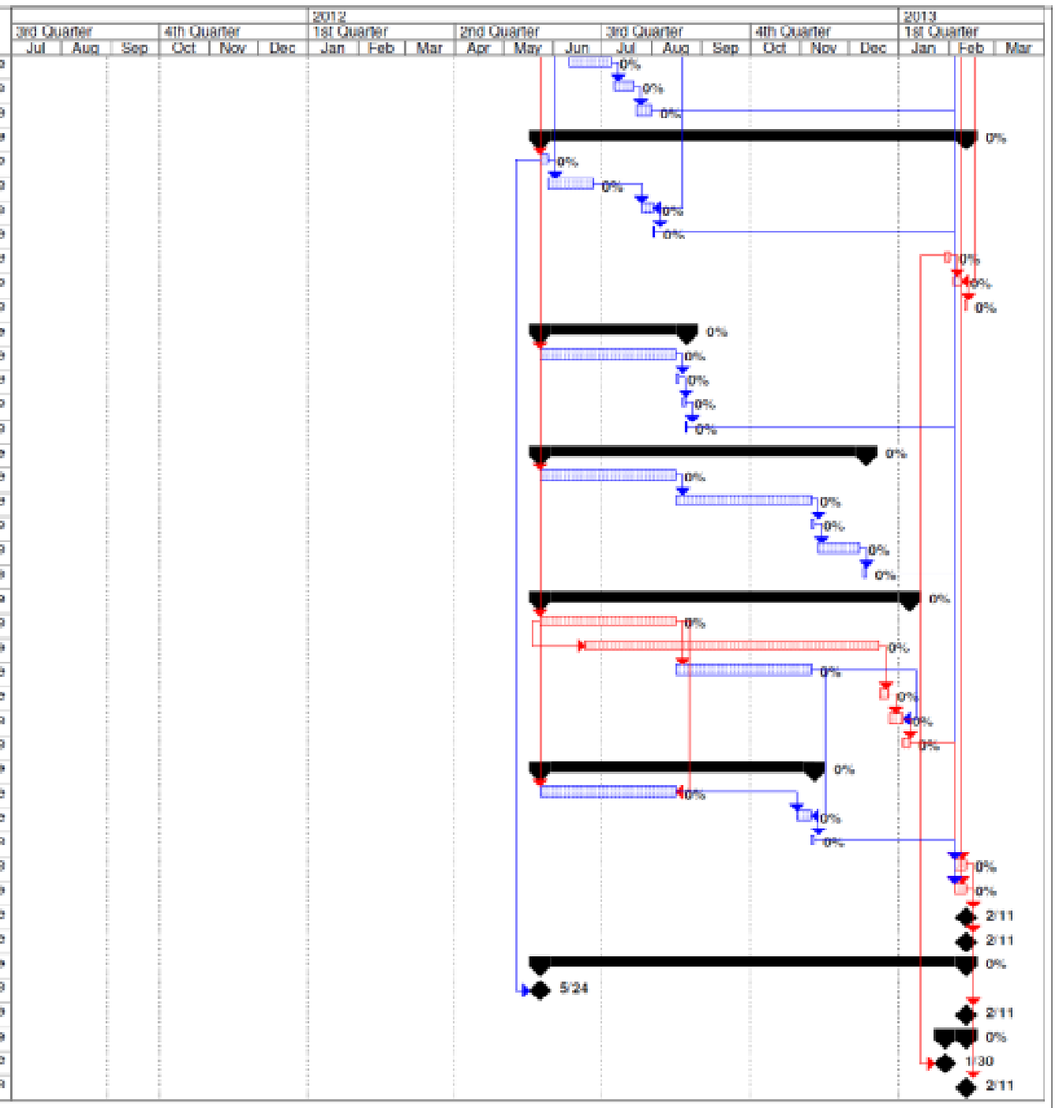



Project: Project1 Exist & Repla Lease
Date: Mon 8/29/11

Critical, Critical Split, Critical Progress, Task, Split, Task Progress, Baseline, Baseline Split, Baseline Milestone, Milestone, Summary Progress, Summary, Project Summary, External Tasks, External Milestone, Deadline

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| ID | Task Name | Duration | Start | Finish | Constraint Type |
|---|---|---|---|---|---|
| 44 | Overhaul, rewind, and balance Rotor | 4 wks | Mon 6/11/12 | Fri 7/6/12 | As Soon As Possible |
| 45 | Ship Rotor to Holyrood | 2 wks | Mon 7/9/12 | Fri 7/20/12 | As Soon As Possible |
| 46 | Rebuild and commission unit | 7 days | Mon 7/23/12 | Tue 7/31/12 | As Soon As Possible |
| 47 | **Exhaust Stack** | **188 days** | **Thu 5/24/12** | **Mon 2/11/13** | **As Soon As Possible** |
| 48 | Remove | 3 days | Thu 5/24/12 | Mon 5/28/12 | As Soon As Possible |
| 49 | Repair/Replace | 4 wks | Tue 5/29/12 | Mon 6/25/12 | As Soon As Possible |
| 50 | Re-install | 5 days | Thu 7/26/12 | Wed 8/1/12 | As Soon As Possible |
| 51 | Commission unit | 1 day | Thu 8/2/12 | Thu 8/2/12 | As Soon As Possible |
| 52 | Remove new stack | 3 days | Wed 1/30/13 | Fri 2/1/13 | As Late As Possible |
| 53 | Re-install | 5 days | Mon 2/4/13 | Fri 2/8/13 | As Late As Possible |
| 54 | Commission unit | 1 day | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible |
| 55 | **Intake media** | **65 days** | **Thu 5/24/12** | **Wed 8/22/12** | **As Soon As Possible** |
| 56 | Order & Manufacture Filter media | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Soon As Possible |
| 57 | Remove | 2 days | Thu 8/16/12 | Fri 8/17/12 | As Soon As Possible |
| 58 | Repair/Replace | 2 days | Mon 8/20/12 | Tue 8/21/12 | As Soon As Possible |
| 59 | Commission unit | 1 day | Wed 8/22/12 | Wed 8/22/12 | As Soon As Possible |
| 60 | **Fuel System Refurbishments** | **144 days** | **Thu 5/24/12** | **Tue 12/11/12** | **As Soon As Possible** |
| 61 | Engineer | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Soon As Possible |
| 62 | Order, Manufacture, Deliver | 12 wks | Thu 8/16/12 | Wed 11/7/12 | As Soon As Possible |
| 63 | Remove | 2 days | Thu 11/8/12 | Fri 11/9/12 | As Soon As Possible |
| 64 | Repair/Replace | 4 wks | Mon 11/12/12 | Fri 12/7/12 | As Soon As Possible |
| 65 | Commission unit | 2 days | Mon 12/10/12 | Tue 12/11/12 | As Soon As Possible |
| 66 | **Electrical & Control Systmes** | **163 days** | **Thu 5/24/12** | **Mon 1/7/13** | **As Soon As Possible** |
| 67 | Engineer | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Soon As Possible |
| 68 | Order & Manufacture Elect & Control Equip | 26 wks | Thu 6/21/12 | Wed 12/19/12 | As Soon As Possible |
| 69 | GT Building Addition | 12 wks | Thu 8/16/12 | Wed 11/7/12 | As Soon As Possible |
| 70 | Remove Existing | 4 days | Thu 12/20/12 | Tue 12/25/12 | As Soon As Possible |
| 71 | Install New System | 7 days | Wed 12/26/12 | Thu 1/3/13 | As Soon As Possible |
| 72 | Commission unit | 2 days | Fri 1/4/13 | Mon 1/7/13 | As Soon As Possible |
| 73 | **Building & Systmes** | **122 days** | **Thu 5/24/12** | **Fri 11/9/12** | **As Soon As Possible** |
| 74 | Engineer | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Soon As Possible |
| 75 | Modify and Refurbish | 7 days | Tue 10/30/12 | Wed 11/7/12 | As Soon As Possible |
| 76 | Commission unit | 2 days | Thu 11/8/12 | Fri 11/9/12 | As Soon As Possible |
| 77 | Complete Unit Test - Lease Parts | 5 days | Tue 2/5/13 | Mon 2/11/13 | As Soon As Possible |
| 78 | Complete Unit Test - Original Replacement | 5 days | Tue 2/5/13 | Mon 2/11/13 | As Soon As Possible |
| 79 | Gas Turbine (GT) In-service (I/S) - Lease Parts | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible |
| 80 | Gas Turbine (GT) In-service (I/S) - Original | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible |
| 81 | **UNIT OUTAGE -Lease Parts** | **188 days** | **Thu 5/24/12** | **Mon 2/11/13** | **As Soon As Possible** |
| 82 | Unit Outage Start | 0 days | Thu 5/24/12 | Thu 5/24/12 | As Soon As Possible |
| 83 | Unit Outage End | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible |
| 84 | **UNIT OUTAGE - Original** | **9 days** | **Wed 1/30/13** | **Mon 2/11/13** | **As Soon As Possible** |
| 85 | Unit Outage Start | 0 days | Wed 1/30/13 | Wed 1/30/13 | As Soon As Possible |
| 86 | Unit Outage End | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible |




Project: Project1 Exist & Repla Lease
Date: Mon 8/29/11

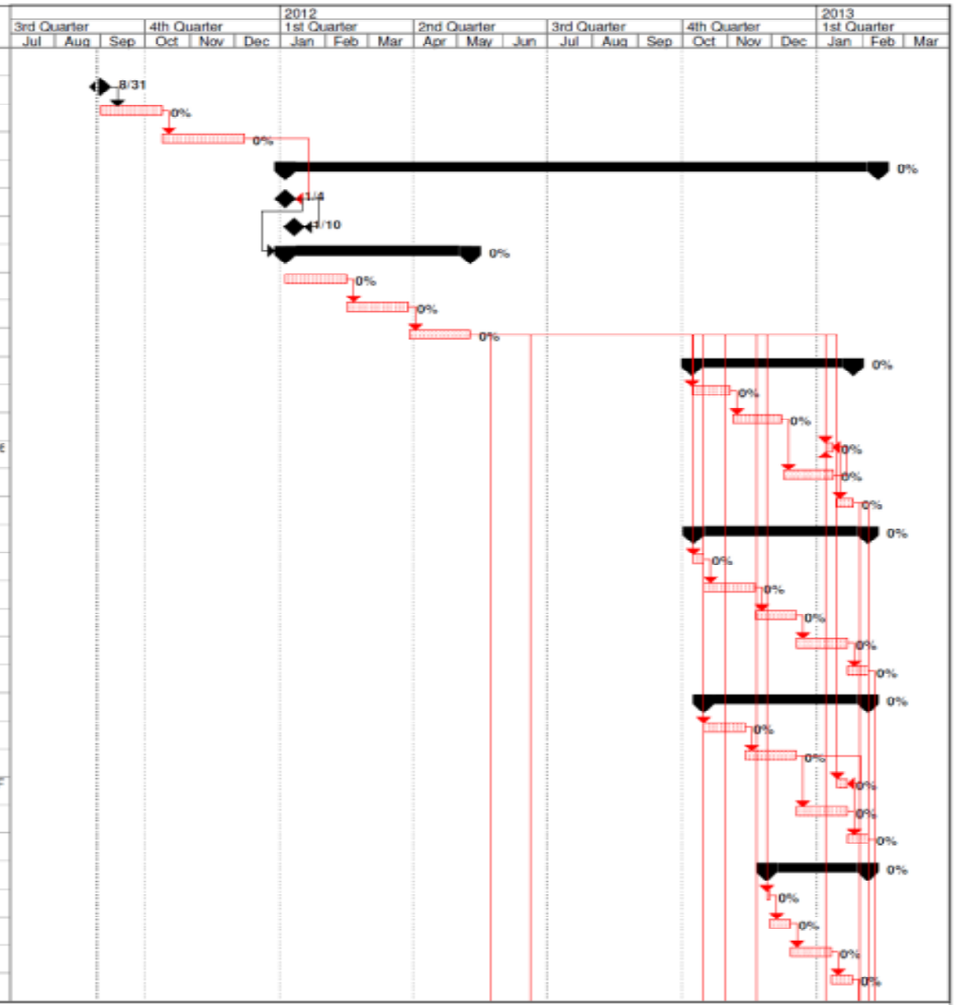
Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

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Figure 2-11 presents a third variation of the basic "earliest return to service" schedule for the existing GTG unit refurbishment. It assumes the purchase and refurbishment for use of used replacements parts for the existing GT unit (the gas generator, the power turbine) to minimize the outage window. Its in-service date is February 2013, but with an outage window of only four months from November 2012 to February 2013. The outage also occurs when Holyrood is normally required to operate, and the actual schedule would likely be shifted six months to allow for a May 2013 to August 2013 outage and August 2013 in-service.

**FIGURE 2-11 EXISTING GTG REFURBISHMENT – ALTERNATE SCHEDULE 3 (USE OF PROCURED AND REFURBISHED GAS GENERATOR AND POWER TURBINE DURING OUTAGE)**

| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 | Finish No Earlier Than | |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 | As Soon As Possible | 2 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 | As Soon As Possible | 3 |
| 5 | **Refurbish Unit** | **288 days** | **Wed 1/4/12** | **Mon 2/11/13** | **As Soon As Possible** | |
| 6 | Project Limited Notice to proceed (LNTP) Approval | 0 days | Wed 1/4/12 | Wed 1/4/12 | As Soon As Possible | 4FF+4 wks |
| 7 | Project Full Notice to proceed (NTP) | 0 days | Tue 1/10/12 | Tue 1/10/12 | As Soon As Possible | 6FF+4 days |
| 8 | **Request for Proposal (RFP) - Engineer/Procure/Co** | **90 days** | **Thu 1/5/12** | **Wed 5/9/12** | **As Soon As Possible** | 6 |
| 9 | Prepare | 30 days | Thu 1/5/12 | Wed 2/15/12 | As Soon As Possible | |
| 10 | Bid | 30 days | Thu 2/16/12 | Wed 3/28/12 | As Soon As Possible | 9 |
| 11 | Award | 30 days | Thu 3/29/12 | Wed 5/9/12 | As Soon As Possible | 10 |
| 12 | **Power Turbine (PT)** | **80 days** | **Mon 10/8/12** | **Fri 1/25/13** | **As Soon As Possible** | |
| 13 | Procure Refurbished Disc and PT Assembly | 4 wks | Mon 10/8/12 | Fri 11/2/12 | As Late As Possible | 11 |
| 14 | Refurbish PT Replacement | 5 wks | Mon 11/5/12 | Fri 12/7/12 | As Late As Possible | 13 |
| 15 | Strip and dissassemble plant | 1 wk | Mon 1/7/13 | Fri 1/11/13 | As Late As Possible | 37,11FS+2 wks,1€ |
| 16 | Ship Rotor to Holyrood | 5 wks | Mon 12/10/12 | Fri 1/11/13 | As Soon As Possible | 14 |
| 17 | Rebuild and commission unit | 2 wks | Mon 1/14/13 | Fri 1/25/13 | As Soon As Possible | 16,15 |
| 18 | **Gear Box Overhaul** | **85 days** | **Tue 10/9/12** | **Mon 2/4/13** | **As Soon As Possible** | |
| 19 | Strip and dissassemble plant | 1 wk | Tue 10/9/12 | Mon 10/15/12 | As Late As Possible | 11FS+4 wks |
| 20 | Ship to overhaul plant | 5 wks | Tue 10/16/12 | Mon 11/19/12 | As Late As Possible | 19 |
| 21 | Overhaul and balance Rotor | 4 wks | Tue 11/20/12 | Mon 12/17/12 | As Late As Possible | 20 |
| 22 | Ship to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | As Soon As Possible | 21 |
| 23 | Rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | As Soon As Possible | 22 |
| 24 | **Avon Gas Generator Overhaul** | **80 days** | **Tue 10/16/12** | **Mon 2/4/13** | **As Soon As Possible** | |
| 25 | Procure Refurbished Disc and PT Assembly | 4 wks | Tue 10/16/12 | Mon 11/12/12 | As Late As Possible | 11 |
| 26 | Refurbish PT Replacement | 5 wks | Tue 11/13/12 | Mon 12/17/12 | As Late As Possible | 25 |
| 27 | Strip and dissassemble plant | 1 wk | Tue 1/15/13 | Mon 1/21/13 | As Late As Possible | 11FS+2 wks,26FF |
| 28 | Ship Rotor to Holyrood | 5 wks | Tue 12/18/12 | Mon 1/21/13 | As Soon As Possible | 26 |
| 29 | Rebuild and commission unit | 2 wks | Tue 1/22/13 | Mon 2/4/13 | As Soon As Possible | 28,27 |
| 30 | **Generator Rewind** | **49 days** | **Wed 11/28/12** | **Mon 2/4/13** | **As Soon As Possible** | |
| 31 | Strip and dissassemble plant | 2 days | Wed 11/28/12 | Thu 11/29/12 | As Late As Possible | 11FS+2 wks |
| 32 | Ship Rotor to overhaul plant | 2 wks | Fri 11/30/12 | Thu 12/13/12 | As Late As Possible | 31 |
| 33 | Overhaul, rewind, and balance Rotor | 4 wks | Fri 12/14/12 | Thu 1/10/13 | As Late As Possible | 32 |
| 34 | Ship Rotor to Holyrood | 2 wks | Fri 1/11/13 | Thu 1/24/13 | As Soon As Possible | 33 |

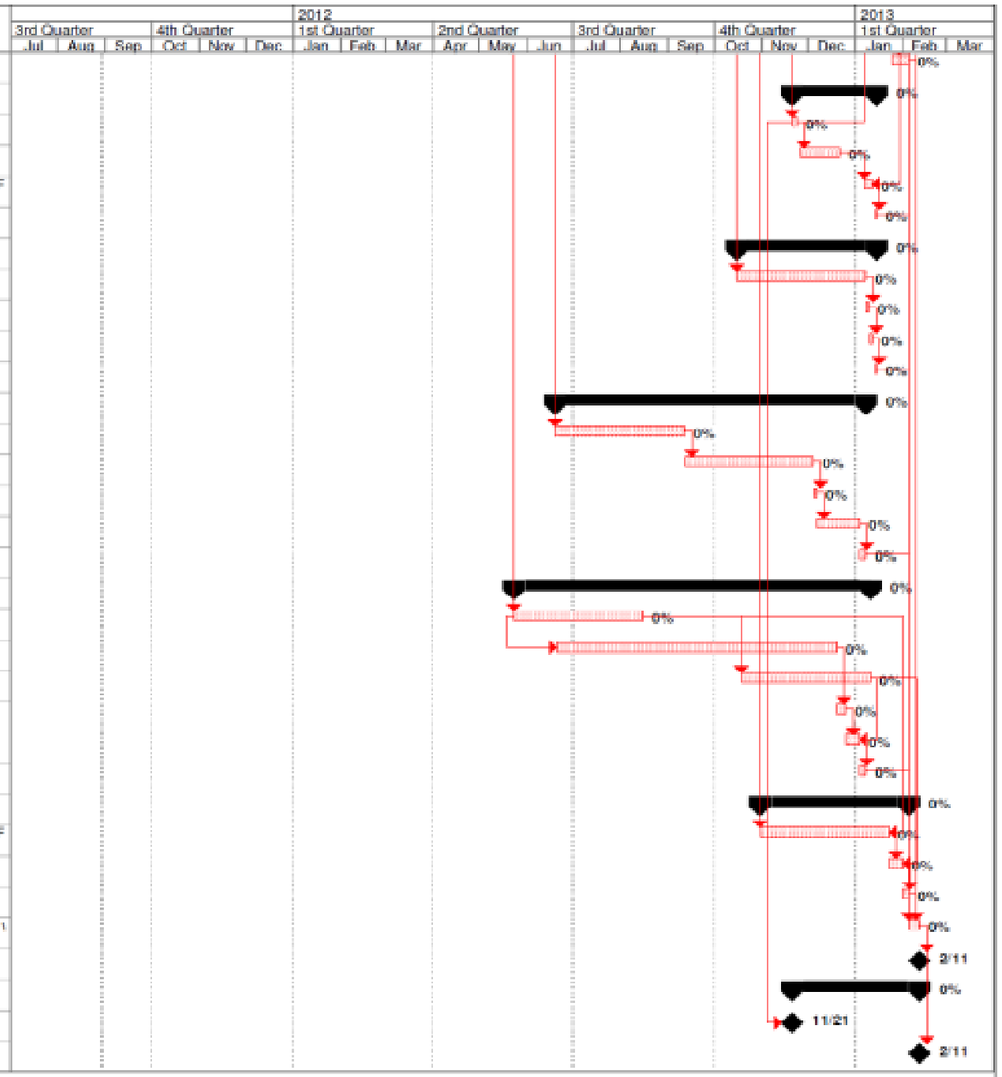



Project: Project1 Exist Repla GT parts
Date: Mon 8/29/11

Critical, Critical Split, Critical Progress, Task, Split, Task Progress, Baseline, Baseline Split, Baseline Milestone, Milestone, Summary Progress, Summary, Project Summary, External Tasks, External Milestone, Deadline

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| ID | Task Name | Duration | Start | Finish | Constraint Type | Predecessors |
|---|---|---|---|---|---|---|
| 35 | Rebuild and commission unit | 7 days | Fri 1/25/13 | Mon 2/4/13 | As Soon As Possible | 34 |
| 36 | **Exhaust Stack** | **39 days** | **Wed 11/21/12** | **Mon 1/14/13** | **As Soon As Possible** | |
| 37 | Remove | 3 days | Wed 11/21/12 | Fri 11/23/12 | As Late As Possible | 11FS+2 wks |
| 38 | Repair/Replace | 4 wks | Mon 11/26/12 | Fri 12/21/12 | As Late As Possible | 37 |
| 39 | Re-install | 5 days | Mon 1/7/13 | Fri 1/11/13 | As Late As Possible | 38FS+2 wks,17FF |
| 40 | Commission unit | 1 day | Mon 1/14/13 | Mon 1/14/13 | As Soon As Possible | 39 |
| 41 | **Intake media** | **65 days** | **Tue 10/16/12** | **Mon 1/14/13** | **As Soon As Possible** | |
| 42 | Order & Manufacture Filter media | 12 wks | Tue 10/16/12 | Mon 1/7/13 | As Late As Possible | 11FS+2 wks |
| 43 | Remove | 2 days | Tue 1/8/13 | Wed 1/9/13 | As Late As Possible | 42 |
| 44 | Repair/Replace | 2 days | Thu 1/10/13 | Fri 1/11/13 | As Late As Possible | 43 |
| 45 | Commission unit | 1 day | Mon 1/14/13 | Mon 1/14/13 | As Soon As Possible | 44 |
| 46 | **Fuel System Refurbishments** | **144 days** | **Wed 6/20/12** | **Mon 1/7/13** | **As Soon As Possible** | |
| 47 | Engineer | 12 wks | Wed 6/20/12 | Tue 9/11/12 | As Late As Possible | 11FS+2 wks |
| 48 | Order, Manufacture, Deliver | 12 wks | Wed 9/12/12 | Tue 12/4/12 | As Late As Possible | 47 |
| 49 | Remove | 2 days | Wed 12/5/12 | Thu 12/6/12 | As Late As Possible | 48 |
| 50 | Repair/Replace | 4 wks | Fri 12/7/12 | Thu 1/3/13 | As Late As Possible | 49 |
| 51 | Commission unit | 2 days | Fri 1/4/13 | Mon 1/7/13 | As Soon As Possible | 50 |
| 52 | **Electrical & Control Systmes** | **166 days** | **Thu 5/24/12** | **Thu 1/10/13** | **As Soon As Possible** | |
| 53 | Engineer | 12 wks | Thu 5/24/12 | Wed 8/15/12 | As Late As Possible | 11FS+2 wks |
| 54 | Order & Manufacture Elect & Control Equip | 26 wks | Thu 8/21/12 | Wed 12/19/12 | As Late As Possible | 53SS+4 wks |
| 55 | GT Building Addition | 12 wks | Fri 10/19/12 | Thu 1/10/13 | As Late As Possible | 53 |
| 56 | Remove Existing | 4 days | Thu 12/20/12 | Tue 12/25/12 | As Late As Possible | 54 |
| 57 | Install New System | 7 days | Wed 12/26/12 | Thu 1/3/13 | As Late As Possible | 56,55FF-1 wk |
| 58 | Commission unit | 2 days | Fri 1/4/13 | Mon 1/7/13 | As Soon As Possible | 57 |
| 59 | **Building & Systems** | **69 days** | **Wed 10/31/12** | **Mon 2/4/13** | **As Soon As Possible** | |
| 60 | Engineer | 12 wks | Wed 10/31/12 | Tue 1/22/13 | As Late As Possible | 11FS+2 wks,53FF |
| 61 | Modify and Refurbish | 7 days | Wed 1/23/13 | Thu 1/31/13 | As Late As Possible | 60,55FF |
| 62 | Commission unit | 2 days | Fri 2/1/13 | Mon 2/4/13 | As Soon As Possible | 61 |
| 63 | Complete Unit Test | 5 days | Tue 2/5/13 | Mon 2/11/13 | As Soon As Possible | 29,35,17,40FS+3 |
| 64 | Gas Turbine (GT) In-service (I/S) | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible | 63 |
| 65 | **UNIT OUTAGE** | **59 days** | **Wed 11/21/12** | **Mon 2/11/13** | **As Soon As Possible** | |
| 66 | Unit Outage Start | 0 days | Wed 11/21/12 | Wed 11/21/12 | As Soon As Possible | 37SS |
| 67 | Unit Outage End | 0 days | Mon 2/11/13 | Mon 2/11/13 | As Soon As Possible | 63 |




Project: Project1 Exist Repla GT parts
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Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

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## 2.9 Annual OMA Cost Estimate to 2020

### 2.9.1 Historical OMA

Historical operations, maintenance and administration (OMA) data was obtained from the station cost database for the period 2000 to 2011. Information prior to that was not available. Also provided were several recent purchase order invoices from Alba Power for recent boroscope and physical inspections that are assumed to be included in the work order totals, but which may be somewhat out of synchronization. Copies of the "Cost Report by Work Order/Asset" are attached in Appendix 3.

**TABLE 2-32 HISTORICAL OMA COST ASSUMPTIONS**

**OMA**

| | Maintenance | | Fueling | Ops | Total |
|---|---|---|---|---|---|
| Year | Work Order k$/Yr OMA | PO Data k$/Yr OMA | k$/Yr Fuel | PO Data k$/Yr OMA | Work Order k$/Yr OMA |
| 2000-2002 | $10 | | | | |
| 2003 | $14 | | $37 | $33 | $83 |
| 2004 | $31 | | $37 | $33 | $100 |
| 2005 | $19 | | $37 | $33 | $89 |
| 2006 | $129 | $100 | $201 | $59 | $388 |
| 2007 | $34 | $74 | $201 | $59 | $293 |
| 2008 | $45 | $15 | $201 | $59 | $304 |
| 2009 | $283 | $182 | $201 | $59 | $542 |
| 2010 | $45 | $50 | $201 | $59 | $304 |
| 2011 | $182 | | $22 | $8 | $212 |
| Av/Yr Hist | $68 | $84 | $126 | $44 | $257 |

Most of the historical costs are for relatively minor repairs and do not include major changes such as controls change outs or other major capital modifications. These major costs are not particularly relevant to the OMA analyses going forward.

Several interesting issues arose during the period:

- Ice and snow blockage of parts of lube oil cooler and fuel oil system (led to enclosure of pumps and filters) identified beginning in 2004 and beyond
- GT generator vibration checks (issue) in 2007
- Leak and pressure check on GT gearbox in 2006. Filter not cleaned regularly. Issue in 2003 (last cleaned filter). Fittings change. Gearbox drain valve change -
- Modify/Addition of gear box lube oil vent to relieve pressure in 2007 and 2008
- Lube oil at gearbox cleanup in 2008, 2009, Attempt to fix by Alba 2010; Increase generator end gearbox bearing drain. Fire 2010/2011.
- Several issues in recent years with snow doors operation and rusting, annual checks done
- 2008 lube oil radiator leak

Several major systems had been replaced/modified: controls (twice), gearbox seals, lube oil radiator

### 2.9.2 Estimated Future OMA

Operating and maintenance (O&M) costs going forward for completely refurbished or new units are not significantly relevant given their level of operation. Most such O&M costs will be for ongoing annual inspection costs. Significant maintenance costs as have been seen recently with the existing unit should not occur if regular inspection and maintenance is undertaken. For completeness, the costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit.

The operating costs are shown for both a refurbished case and a non-refurbished case. The assumptions used for fuel, operations, and electricity value are illustrated in Table 2-33. The "electricity value" is a revenue stream premised on recovering fuelling costs plus marginal operating and maintenance costs. The maintenance costs are based on historical maintenance data and information from vendors. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

**TABLE 2-33 EXISTING GTG – FUTURE OMA COST ASSUMPTIONS**

**Assumptions**

| | | Fuelling |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 13,656 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,173 |
| Electricity Value (E) = AxB/1000 + $50 Mtce | $/MWh | $343 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| Operations | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

The following OMA costs have been assumed going forward. The non-refurbished case includes an assumption of an equipment failure with modest consequential damage in 2016. "Electricity value" is a revenue stream for electricity sold during testing.

**TABLE 2-34 EXISTING GTG – FUTURE OMA COSTS**

**Existing Unit**
**1000's Cnd $ - 2011/Yr**

| | Maintenance | | Operations | | Fuelling | | Sub-Total | | Electricity Value | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab |
| 2012 | $15 | $15 | $0 | $0 | $0 | $0 | $15 | $15 | $0 | $0 | $15 | $15 |
| 2013 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2014 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2015 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2016 | $20 | $1,500 | $40 | $1 | $176 | $88 | $236 | $1,589 | ($206) | ($103) | $30 | $1,486 |
| 2017 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2018 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2019 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2020 | $0 | $0 | $40 | $0 | $176 | $0 | $216 | $0 | ($206) | $0 | $10 | $0 |
| TOTAL | $155 | $1,605 | $323 | $1 | $1,408 | $88 | $1,885 | $1,694 | ($1,648) | ($103) | $238 | $1,591 |

The actual maintenance costs going forward can be expected to vary widely and could easily be twice those noted, depending on the actual operation of the unit. The costs for operations and for fuel, as well as fuel value are comparable in value or larger.

# 3 TASK B – REPLACEMENT OPTIONS ASSESSMENT

## 3.1 Task Details

Mobile/transportable GT and diesel generators were evaluated for their ability to provide Holyrood Thermal Generating Station with black start capability until the year 2020. Following 2020, it is expected the Holyrood plant will no longer be operating as a generating facility**.** The mobile/transportable gas turbine and diesel generators would be available post-2020 for other temporary power uses within NL Hydro's system, and possibly for similar uses prior to 2020 as warranted.

## 3.2 Assessment Basis

The assessment will be based on an evaluation of Hydro and vendor supplied information regarding the existing Holyrood infrastructure, and new or nearly new transportable power generation units which will either be GT or diesel.

**TABLE 3-1 ASSESSMENT CRITERIA**

| Criteria | Description |
|---|---|
| Generator | 1) Gas Turbine Gen Set 5 MW X 2 – new or nearly new/used<br>2) Diesel Gen Set 2 MW X5 – new or nearly new/used |
| Transportability | Transportability - system must be capable of being set up within a week, to ensure that the system can be used elsewhere as needed, particularly after its service has ended at Holyrood. Must comply with local road regulations. |
| Footprint | Minimize space site requirement of the generator. Set selected must be able to fit on the parking lot adjacent to the emergency response building. This site was selected through discussions with Nalcor personnel. |
| Electrical output | The system must be able to generate at 13.8 KV, combined system output to be approximately 10 MW peak, with a block load of about 3 to 3.5 MW. |
| Black Start | Systems must be capable of black start function for the plant and require no more than 600 volt 316 kW for black start |
| Fuel Type | Must use No. 2 fuel oil |
| Site Preparation | Unit trailers must be self levelling and require no concrete foundation. |
| Certification | CSA Certification |
| Emissions | **Diesel Gensets**: The equipment is assumed to be classified as stationary. The province has jurisdiction, and all existing regulations apply. (In Ontario, the generally accepted practice is that a unit is considered to be stationary if it remains within the same municipal boundaries for 12 continuous months regardless if it's mounted on wheels or not.)<br>Regulations require a dispersion model be prepared to demonstrate compliance with regulations of ground level concentrations of pollutants at the property boundaries or nearest critical receptor. The key parameter is oxides of nitrogen (NOx) and the permitted concentration limit is, for non-emergency generation, |

| | |
|---|---|
| | 400 micro-grams per cubic meter of air.<br><br>The emergency generator limit permitted in NL is not readily identifiable (Ontario $NO_x$ concentration limit for emergency generators is 1880 mg/m3 of air).<br><br>Newfoundland & Labrador air emissions regulations do require Best Available Control Technology (BACT), but provide for reasonable economics and also for Ministerial exemptions. This would need to be addressed in environmental regulatory approvals.<br><br>**GT Gensets:** Canadian Council of Ministers of the Environment (CCME) 1992 National Emission Guidelines for Stationary Combustion Turbines may be followed. They do not apply to "Emergency" or "Standby GT" (a unit not normally required for the supply of energy or motive power to meet normal system operational requirements. A "Peaking GT" is a unit ordinarily used to supply electric or motive power in periods of high demand but typically has restricted hours (<3000 hours over 5 years in summer; <7500 hours over 5 years total). The GT Emission Guideline values for diesel fuel are as follows. These units may, however, still have to meet ground level concentration limits, assumed to be 400 ug/$m^3$ of air, based on dispersion modeling.<br><br>Peaking — Emergency<br>$NO_X$ — 530 g/GJ — Exempt<br><br>Notes:<br><br>g/GJ = grams of NOx as nitrogen dioxide (NO2) per gigajoule (GJ) of net electrical energy output (where 1 megawatthour (MWh) of electricity = 3.6 GJ.<br><br>AMEC has assessed the diesel emission regulations and considers that the installation would be considered a "stationary source". It is likely to also be considered an emergency unit. |

## 3.3 Options 2 – 2 x 5 MW GT (New, Nearly-New)

### 3.3.1 Description

In this option, two 5 MW units would be utilized to provide black start capability. Sizing at 5 MW each would allow the units to be more transportable than larger units. Both units would be required to operate simultaneously to provide sufficient power for black start. Vendor information was received from TOROMONT CAT, PETERSON Power Systems CAT, Solar Turbines, and Rolls Royce/Allison Turbine.

These will be mobile units supplied by a vendor and will not require a GT building. Several items will however be required, such as:

- Turbine trailers area with site work to ensure sufficient ground support for the mobile turbines.
- A pre-engineered shelter for electrical equipment, including concrete foundation and floor slab. Approximately 30 ft x 30 ft.
- A reinforced concrete pipe/trench for cables running from the turbines to the main building and from the turbines to the existing fuel lines.
- Electrical and I&C connections to the existing plant facilities

### 3.3.2 Performance Characteristics

The performance characteristics are based on information from Solar Turbines Taurus 60, (**APPENDIX 4).** Vendors are Peterson, Toromont, and Solar. Peterson also sells used Taurus 60 gen packages.

**TABLE 3-2 TURBINE PERFORMANCE CRITERIA**

| Criteria | Value |
|---|---|
| KW Gross Output @ ISO Conditions | 5,510kW |
| Voltage | 13.8 KV |
| Site Ambient Temperature for Performance Analysis: | 15 C (59 F) |
| Site Elevation for Performance Analysis: | 320 Feet |
| Site Ambient Relative Humidity for Performance Analysis: | 60% |
| Turbine Inlet Pressure Loss: | 4" H20 (inches of water gauge pressure) |
| Turbine Outlet Pressure Loss: | 4"H20 |
| Turbine Fuel Consumption @ specified site conditions (Lower Heating value(LHV) | 59 MBTU/hr (Millions of British Thermal Units Per Hour) |
| KW Gross Output @ specified site conditions: | 5,301 kW |
| Turbine Auxiliary Power Consumption: | 15 kW |
| Net Turbine Power Production | 5,286 kW |
| Black Start kW Requirement (Turbine Generator Set Only) | A 250kW, 480VAC, 3 phase, Black Start Generator is required for turbine starting in the event 13.8kV power is not available. |
| Fuel Consumption | 8.0 gallons per minute (gpm) (30 Liters/min (L/min)). This implies for black start with two units running there would be a total of 16 gpm (60 L/min) and assuming a 24 hour period would require almost 24,000 gallons (90,849 L) of fuel. The current fuel oil tanks as previously noted are 26,417 gallons (100,000 L) each. |
| Inlet Filter Media | Suitable for Marine Environment |

#### 3.3.2.1 Emission Requirements

For a peaking GT unit on oil emission limits would be:

| | |
|---|---|
| $NO_x$ (Oxides of Nitrogen (NO,$NO_2$): | 530 g ($NO_x$ as $NO_2$)/ GJ electric energy (1 MWh = 3.6 GJ). |
| $SO_2$ (Sulphur dioxide): | 970 g $SO_2$/GJ of electric output. Current 0.2% sulphur (S) in oil (specification) = approximately1572 grams as $NO_2$/GJ output |
| CO (Carbon Monoxide): | 50 ppm at full load (corrected to 15% O2, dry basis) |

Operating time limits could be placed on peaking units. An emergency unit for black start only might be exempt, but could thereby limit its future.

No specific GT applicable Newfoundland air pollution regulations were identified. There is however a general requirement for Best Available Control Technology (BACT), with provisions for an exemption based on economics and on a Ministerial exemption for practical purposes. The typical emission performance for Solar GT units on diesel oil is presented in Table 3-3.

**TABLE 3-3 SOLAR GT TYPICAL EMISSIONS**

| Exhaust Emissions At Stack (Solar) | Measurement | Per Unit |
|---|---|---|
| $NO_x$ | parts per million (ppm) @ 15% O2 in flue gas | 74 |
| | lb/MMBTU, HHV (Pounds/Million BTU, Higher Heating Value) | 0.284 |
| | Pounds/Hour (lb/hr) | 17.8 |
| | tons/year | 78 |
| CO (Carbon Monoxide) | ppm @ 15% O2 | 25 |
| | lb/MMBTU, HHV | 0.058 |
| | lb/hr | 3.7 |
| | tons/year | 16 |
| UHC (Unburnt Hydrocarbons | ppm @ 15% O2 | 25 |
| | lb/MMBTU, HHV | 0.033 |
| | lb/hr | 2.1 |
| | tons/year | 9.2 |
| VOC Volatile Organic Compounds | ppm @ 15% O2 | 25 |
| | lb/MMBTU, HHV | 0.033 |
| | lb/hr | 2.1 |
| | tons/year | 9.2 |
| $PM_{10}/PM_{2.5}$ (Particulate Matter – Less than 10 and 2.5 microns in size) | lb/hr | 2.4 |
| | lb/MMBTU, HHV | 0.039 |
| | tons/year | 10.7 |
| $SO_2$ | lb/hr | 12.91 |
| | lb/MMBTU, HHV | 0.20555 |
| | tons/year | 56.5 |
| Greenhouse Gas Emissions | lbs of carbon dioxide ($CO_2$)/MMBTU (HHV) | 162 |

$SO_2$ emissions depend upon the fuel's sulfur content. The $SO_2$ estimate is based upon the assumption of 100% conversion of fuel sulphur to $SO_2$, using assumed values for various fuels that may not reflect actual fuel composition.

#### 3.3.2.2 Transition

The existing GT system is to remain active while new system is independently installed. A short outage will be required during a transition period during which final connections to the electrical, instrumentation and controls, and fuel systems are made.

#### 3.3.2.3 Decommissioning

The existing GT unit will be decommissioned, including those parts of the fuel system and electrical connections not required for the new units. This will occur once the new transportable units are in place and operational. A modified fuel offloading/receiving system will remain.

### 3.3.3 General Arrangement Sketch

See attached GA sketch based on dimensional information provided by Solar Turbines located in Appendix 4.

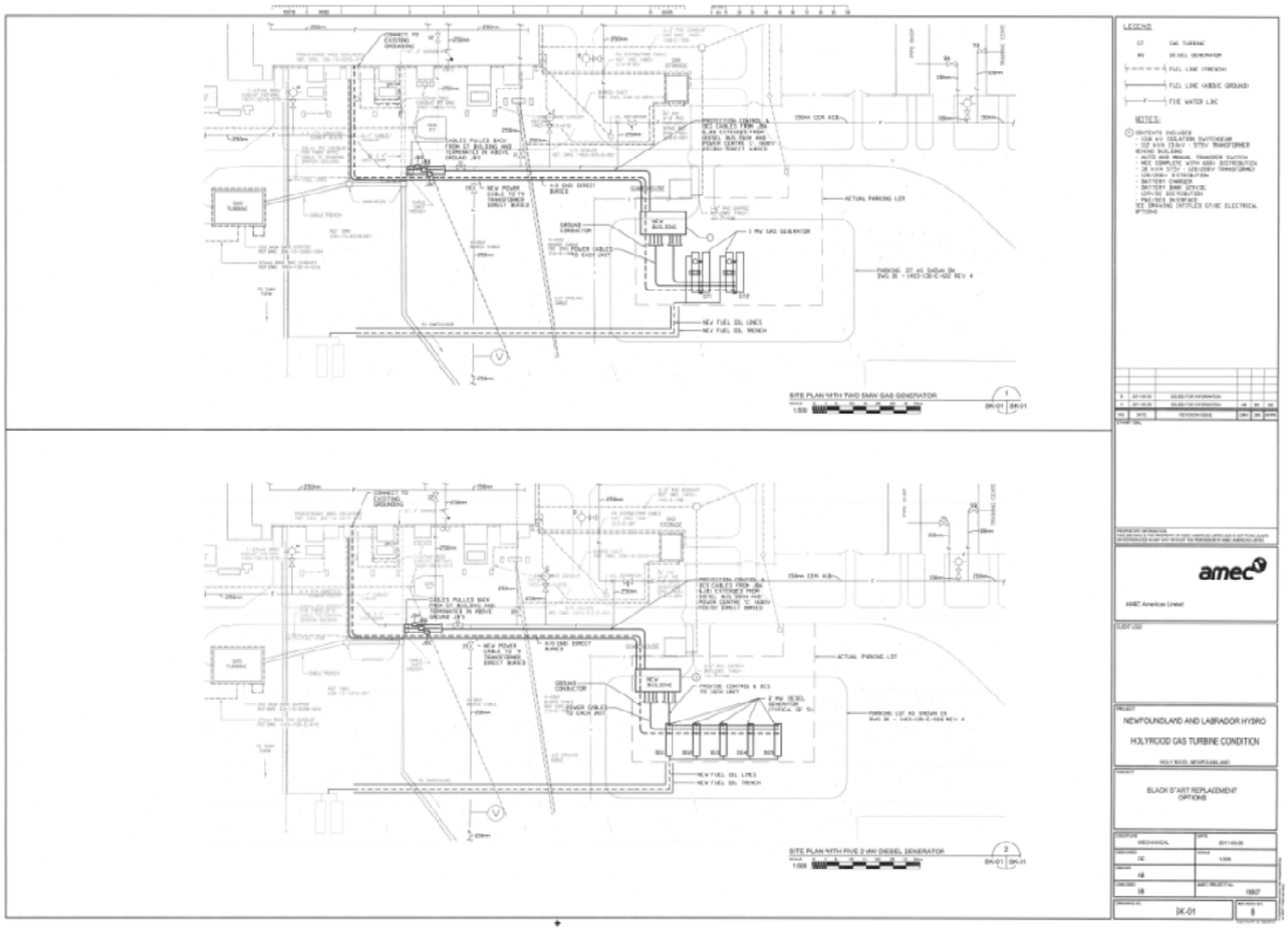



**FIGURE 3-1 GENERAL ARRANGEMENT - 2 X 5 MW GAS TURBINE GENERATORS**



### 3.3.4 Capital Cost Estimate

The following estimates are based on budgetary information provided by Solar Turbines (Details in Appendix 4) and Peterson Power Systems (Details in Appendix 5), and Rolls Royce (details in Appendix 6). Following a review of the vendor information, it appears that used units can be available much quicker than a new purchase. The vendors contacted noted that they did not typically have many of these systems available and that they are sold fairly quickly. On Power Inc who use the Rolls Royce 501 turbine noted that they have 4 units being refurbished for sale which may be able to convert to a mobile configuration. The price would be approximately $ 1 M less than a new package.

Note that Peterson Power Systems deals with the rental and sale of used Taurus mobiles whereas Solar Turbines deals with the sale only of new Taurus mobiles. Rolls Royce has indicated that they would require about 1 year for delivery.

There is not expected to be a significant difference in price between the New and Nearly New options, the advantage between these options is the possibility that a Nearly New set of units will be available and lead/delivery times are significantly reduced.

**TABLE 3-4 SOLAR TURBINE QUOTE FOR NEW TRANSPORTABLE GTG**

| Item | Description | Unit Price | Quantity | Cost |
|---|---|---|---|---|
| 1. | Liquid Fuel TAURUS 60-7901S Mobile Power Unit Turbine Generator Set (New) Solar Quote **APPENDIX 4** | $4,535,000.00 | 2 | $9,070,000.00 |
| 2. | Commissioning Parts, Start-up, and Site Testing | $70,000 | 2 | $140,000 |
| 3 | Shipping | $92,100 | 2 | $184,200 |
| 4 | 6% Balance of Plant Contingency | $5,500 | 2 | $11,000 |
| 5 | Estimation of cost per ISO rating kilowatt for selected equipment | $853 | | $0 |
| 6* | Training* | $9720 | 1 | $29,160 |
| 7 | Mobile Winterization Package (-40 C) | $219,000 | 2 | $438,000 |
| 8 | Marine Grade Inlet Air filter | $12,000 | 2 | $24,000 |
| | | | | $9,896,360 |

- Duties and taxes not included in estimate.
- This quote is provided for budgetary purposes only and does not represent a firm quote.
- Based on Peterson rates.

**TABLE 3-5 ROLLS ROYCE QUOTE FOR NEW TRANSPORTABLE GTG**

| Item | Description | Unit Price | Quantity | Cost |
|---|---|---|---|---|
| 1. | Rolls Royce Allison 501-KB7 mobile GenSet, **APPENDIX 6** | $4,300,000.00 | 2 | $8,600,000.00 |
| 2. | Commissioning Parts, Startup, and Site Testing | $70,00.00 | 2 | $140,000.00 |
| 3 | Shipping | $92,100.00 | 2 | $184,200.00 |
| 4 | 6% Balance of Plant Contingency | $5,500.00 | 2 | $11,000.00 |
| 5 | Estimation of cost per ISO rating kilowatt for selected equipment | $853.00 | | $0.00 |
| 6 | Training | $9720.00 | 3 | $29,160.00 |
| 7 | Mobile Winterization Package (-40 C) | $219,000.00 | 2 | $438,000.00 |
| 8 | Marine Grade Inlet Air filter | $12,000.00 | 2 | $24,000.00 |
| | | | | $9,426,360.00 |

**TABLE 3-6 PETERSON QUOTE FOR NEARLY NEW/USED GT'S**

| Item | Description | Unit Price | Quantity | Cost |
|---|---|---|---|---|
| 1. | Liquid Fuel TAURUS T60 Mobile Power Unit Turbine Generation I Generator Set (Used) Peterson Quote (APPENDIX 5) | $3,800,000.00 | | $7,600,000 |
| 2. | Commissioning Parts, Startup, and Site Testing | $ 63,900.00 | | $127,800 |
| 3 | Shipping | $ 92,100.00 | | $184,200 |
| 4 | 6% Balance of Plant Contingency | $ 5,500.00 | | $11,000 |
| 5 | Estimation of cost per ISO rating kilowatt for selected equipment | $ 853.00 | | $0 |
| 6 | Training | $ 9,720.00 | | $29,160 |
| 7 | Mobile Winterization Package (-40 C) | $ 219,000.00 | | $438,000 |
| 8 | Marine Grade Inlet Air filter | $ 12,000.00 | | $24,000 |
| | | | | $8,414,160 |

### 3.3.4.1 Gas Turbine Trailer Units

For consideration under this project, GT packaged trailer systems shall have the following systems and items included with the gas turbine trailer or support trailer. The following is based on information provided by Solar Turbine (Appendix 4).

**TABLE 3-7 TRANSPORTABLE GAS TURBINE PACKAGE COMPONENTS**

| Component | Description |
|---|---|
| Turbine MODULE: | 5.2 MW Output, 13.8 Kilovolts, 60 Hertz, Direct drive starter and lube system, Lube oil cooler, Turbine Weatherproof acoustic enclosure, Power control room weatherproof acoustic enclosure, Fuel oil filter, High Temperature Detection and Alarm, Auxiliary Systems, Lights, On Crank and On Line Water Wash, Ventilation Silencers and Fans, CO2 Fire Suppression System, Fire Detection and Gas Monitoring System, High Efficiency Combustion Air Barrier Filter and Silencer, Trailer mounted exhaust stack and silencer, Control System with local and remote interface and monitoring. |
| TURBINE TRAILER (Model TK95LCS) | Tri-Axle Transport Trailer with Two Axle Pivoting Booster Length 48' + 14'1" Booster (removable at site) Width 8'6", 9'0" across trailer axles 133" Swing Clearance 49" 5th wheel Height (loaded) Air Ride Suspension and Air Raise and Lowering Kit Steel Disc Wheels with 275/70R x 22.5 Tire Three Tail Light Package Landing Gear (2) 6 Additional Landing Gears with Soil Bearing Plates for Levelling/Stabilization at Site Overall transport height: 14'2" Approximate transport weight: 118,000 lbs (without tractor) |
| POWER CONTROL MODULE (consists of the following): | Power Control Room (PCR) mounted on Two Axle Transport Trailer, Power Control Room HVAC system, Generator Main Circuit Breaker, Single interface point to power grid, Auxiliary Transformer Feeder Circuit Breaker, Bus PTs, Feeder CTs, Metering CTs and PTs, Beckwith M-3425 Protective Relay Module with the following relays:- Impedance (21), Reverse Power Protection (32), Loss of Field Protection (40), Negative Phase Sequence Protection (46), PT Blown Fuse Protection (60), Time Overcurrent Protection (50/51 V), Neutral Overcurrent Protection (51 N) – utilized in grounded site design, Bus Ground Fault Detection (59N) – utilized in ungrounded site design, Generator Differential Fault Protection (87 G), One High Speed Tripping Relay (86) for Circuit Breaker Trip, Lockout, and Turbine Shutdown Settings, Programming, and Testing, Lightning Arrestor and Surge Capacitor, Motor Control Center. Serves Turbine Generator Auxiliary Loads, 120VDC Turbine Generator Battery System with Charger, Dedicated 120VDC Switchgear Battery System with Charger, Start Motor Variable Frequency Drive (VFD), DC Backup Lube Oil Pump Contactor, Interior Lighting, Photocell Controlled Exterior Lighting at Access Doors, Emergency Eyewash Station, Ancillary Equipment. Installed onto the Power Control Room Module are the following: Gas Turbine Lube Oil Cooler, Neutral Ground Resistor, Auxiliary Load Transformer |
| Power Control Room Trailer (Model TK70LCS) | Two Axle Transport Trailer, Trailer Length 46' Overall, Width 8'6", 49" 5th wheel Height (loaded), Air Ride Suspension and Air Raise and Lower Kit, Steel Disc Wheels with 255/70R x 22.5 Tires, Three Tail Light Package, Landing Gear, 4 Additional Landing Gears with Soil Bearing Plates for Levelling/Stabilization at Site, Overall Transport Height: 14'0", Approximate transport weight: 48,000 lbs. (without tractor) |

### 3.3.4.2 Site Civil Works

Site/civil works requirements are primarily related to the gas turbine generator trailer site, and to electrical and fuel connections. The major costs are expected to be:

- Confirming the bearing capacity of soil = $4,000
- Pre-engineered shelter for elec. equipment = $45,000
- Concrete cable trench = $70,000

Oil piping excavation is included in the cost of the piping.

### 3.3.4.3 Gas Turbine Generator Unit Modifications

For this application, the gas turbine units should be provided with air filter media suitable for use in a marine environment as well as have coatings on external components designed for such environments.

### 3.3.4.4 New Gas Turbine Generator Mechanical Requirements

Aside from fuel oil supply, it is expected that the gas turbine units would be self contained and not require any additional mechanical equipment. If required for the water wash system, a water line would be provided.

**Connection and Changes to Existing Oil System**

From supplier information, each turbine at its maximum output would consume fuel at a rate of about 8.0 gpm (30 L/min). This implies for black start with two units running there would be a total of 16 gpm (60 L/min). For a 24 hour period, the fuel oil storage requirement would be about 24,000 gallons (90,849 L) of fuel. The current Fuel oil tanks as previously noted are 26,417 gal (100,000 L) each.

The fuel requirement makes portable tanks impractical for the 8 year solution and this will also have to be considered in the gas turbine transportability consideration. The new gas turbine units will be located approximately 160 m from the existing GT building and will require new fuel oil supply and return piping from the existing system. Since two gas turbines would be provided under this option it is anticipated that only two line connections would be required. Piping could be routed through a trenched containment system.

**TABLE 3-8 NEW GTG – MECHANICAL SYSTEM COSTS**

| Item | Cost |
|---|---|
| 3” supply and return fuel line | $77,100.00 |
| Project Engineering Costs Mechanical | $17,000.00 |

### 3.3.5 New Gas Turbine Option – Electrical, Instrumentation, and Control Requirements

Option 1 is 2 x 5 MW gas turbine generators rated at 13.8 kV. This option involves the replacement of the existing GTG with two (2) GT units rated at 5 MW. Each has a generator output voltage of 13.8kV and is connected to the delta primary of the existing T9 transformer.

#### 3.3.5.1.1 Connections to the Existing Electrical and Control System

Each GT unit will be a completely self contained capable of operating in 'isochronous' or 'droop' mode, having its own main breaker (52), AVR, control and protection, synchronizing, load sharing, paralleling, monitoring and ability to connect to the existing station DCS.

All these functions will connect to a new building. Each generator breaker will be cabled to an item of isolating switchgear. The isolating switchgear will consist of two (2) 13.8kV disconnect switches, one (1) fused disconnect for auxiliaries, and one disconnect for connection of the zig-zag grounding transformer.

An isolation switch allows the individual GT unit to be taken out of service at any time. Each generator breaker (52) is synchronized for connection to the station service bus through the 13.8kV:4160V transformer T9, either individually or as a pair of generators.

The two GT units will be designed with high resistance grounding consisting of a grounding transformer and NGR to limit the ground fault current to less than 10A as normal standard.

The governor and voltage regulation control of the two units is common in utilities. Another advantage is the reliability of the emergency supply source and it is felt the probability of successful starts of one of the two units is better than one GT. For essential auxiliaries loads it requires only one unit running to secure the station during total loss of AC power (black-out).

The 13.8kV fused disconnect FSWI will feed a 112 kVA, 13.8 kV:575 V, 3 phase transformer to provide 600 V service via a new 600 A, 600 V, 3 phase, 60 Hz, 3 W MCC. The MCC will typically provide starters or fused disconnects for pumps, heating, 120/208 V distribution via a 30 kVA transformer and the battery charger. The battery charger supplies the 129 VDC battery and distribution.

Alternative supplies to the MCC will be via an automatic transfer switch (ATS) and a manual transfer switch (MTS), and will be from the diesel bus DB34 and power centre 'C', both in the powerhouse.

Protection and Control/DCS (P&C/DCS) interfaces will combine the requirements of the new units with the requirements of the existing T9 transformer and 4160V breaker SSB2.

#### 3.3.5.1.2 Changes to existing EI and C System

The existing protection, control and DCS cables entering the present GT building will be pulled back and terminated in a weatherproof Junction Box (JB). New teck cables will be connected to these existing cables and direct-buried from the JB to the P&C/DCS interface in the new building.

Similarly, the 600 V feeds from the diesel bus DB34 and power centre 'C' will be pulled-back and terminated in weatherproof JB's. New teck cables will be connected to these existing cables and direct-buried from the JB's to the manual transfer switch (MTS) in the new 'building'.

All new weatherproof JB's will be mounted above ground.

Power cables from the common bus of the isolating switchgear to the existing T9 transformer will replace the existing cables, and will be direct-buried from T9 transformer to the switchgear.

Changes will be made as necessary to the P&C located in Panel 13 (in the powerhouse) and also in Panel 2 (in the powerhouse). Screens will be reconfigured in the control room involving the two new units and their monitoring, control, indication, and alarm functions.

Each unit will be capable of operating in parallel when connected to an isolated 4160 V bus through a transformer (T9 Step-down), i.e. isochronous mode load sharing.

Each unit will be capable of energizing step-down transformer T9 to pick-up essential loads on the 4160 V bus.

The two unit operation will be controlled through a master controller to direct which unit is to pick-up dead-bus, and which unit is to synchronize with the other unit.

The start/stop commands are given from the master controller for auto-operation or manually from the control room.

**Voltage Drop on the 4160 V Bus**

The voltage drop on the 4160 V bus during starting the largest MV motor - 3000 horsepower (hp) boiler feed pump (BFP) motor under the condition of both 5 MW units running (in islanded mode) is about 10% below the recommended minimum of 80% by NEMA MGI. At the same time, starting of a 3000 hp BFP with isolation transformer was found to be unacceptable following preliminary simulation calculations from ETAP. Therefore a detailed procedure must be prepared for the black-start of MV motors.

### 3.3.5.2 4160 V Generator Voltage Option

The 2 x 5 MW generators with outputs at 4160 V are no longer considered for the following reasons:

1. The 4160 V generator characteristics are not suitable for large motor starting, even without the step-down transformer.

2. The distance between the generators and the 4160 V bus is long (+200 M), therefore the voltage drop will be more, which results in costly power cables.

3. The existing ground fault current of the 4160 V bus is 1000 A, therefore the generators must have the generator neutral current of 1000 A. With low grounding resistance there is the possibility of third harmonic current circulating from one generator to another. The 4160 V diesel gensets submitted by the vendor cannot be connected to 4160 V because of them being unable to withstand the 1000 A ground fault on the 4160 V bus.

4. With generator connected directly to the 4160 V bus which is normally fed from the grid, three-phase short circuit current contribution from the grid (to the internal fault near the line end of the generator winding), is significant which results in more damage to the generator windings.

In conclusion, this option is not preferred compared to the other option of 2 x 5 MW units.

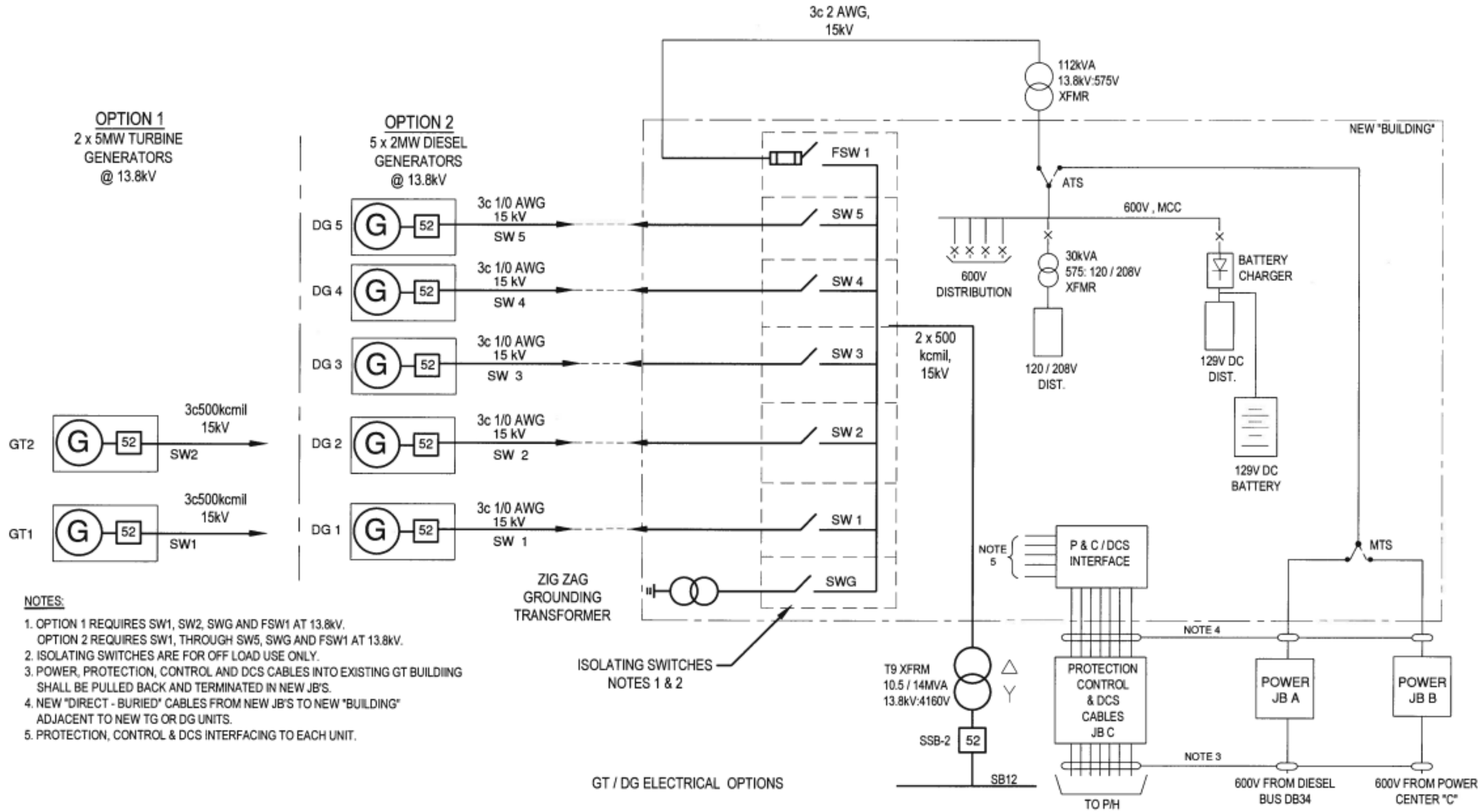



**FIGURE 3-2 SINGLE LINE SKETCH – NEW GAS TURBINE GENSET**

**TABLE 3-9 ELECTRICAL & CONTROL EQUIPMENT AND INSTALLATION COSTS (OPTION 1) 2 X 5MW TG'S**

| Item # | Desciption | Qty | Unit | Material | Labour | Total | Comments |
|---|---|---|---|---|---|---|---|
| 1 | 3c500 kemil, Teck 15kV cable (2 runs) | 550 | m | 112,750 | 10000 | 122,750 | Power from T9 to switchgear and to generators |
| 2 | 13.8kV isolating switchgear (3+1 fused switch) | 1 | ea | 95,000 | 10,000 | 105,000 | |
| 3 | P&C/DCS interface | 1 | ea | 55,000 | 10,000 | 65,000 | Will contain interfacing requirements of the new units to T9 and SSB2. |
| 4 | 10 x 3c12AWG, Teck, 1000V cable | 250 | m | 960 | 2250 | 3210 | from P&C/DCS interface to GTl and GT2 for protection and control |
| 5 | 2 x 25c16AWG, Teck, 1000V cable | 350 | m | 8505 | 3150 | 11655 | Cables from P&C/DCS interface to junction box JBC |
| | 4 x 4c12AWG, Teck, 1000V cable | 700 | m | 3290 | 6300 | 9590 | Cable from FSWI to 112kV transformer |
| | 1 x 12C12AWG, Teck, 1000V cable | 175 | m | 2240 | 1575 | 3815 | Cable ATS to MTS and JBA/JBB to MTS |
| 6 | 3c2AWG, Teck, 15kV cable | 15 | m | 945 | 250 | 1195 | |
| 7 | 2 x 3c1/0, Teck, 1000V cable | 125 | m | 4500 | 1125 | 5625 | |
| 8 | 112kVA, 13.8kV:575V, 3ph, 60Hz transformer | 1 | ea | 30000 | 3000 | 33000 | |
| 9 | 200A, 600V, 3ph, 60Hz automatic transfer switch | 1 | ea | 5336 | 1500 | 6836 | |
| 10 | 200A, 600V, 3ph, 60Hz manual transfer switch | 1 | ea | 2000 | 1000 | 3000 | |
| 11 | MCC, 600A, 600V, 3ph, 3W | 1 | ea | 30000 | 5000 | 35000 | |
| 12 | 30kVA, 575:120/280V, 3ph, 60Hz transformer | 1 | ea | 1000 | 500 | 1500 | |
| 13 | 129VDC distribution panel, motor starters and disconnects | 1 | ea | 35000 | 6500 | 41500 | |
| 14 | 100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers | 1 | ea | 1418 | 350 | 1768 | |
| 15 | 600V, battery charger, 129VDC output | 1 | ea | 16,000 | 3220 | 19,220 | |
| 16 | 129VDC battery bank | 1 | ea | 39,000 | 7500 | 46,500 | |
| 17 | All interconnecting cabling | 1 | lot | 16000 | 12000 | 28000 | Includes MCC feeders, heating and lighting |
| 18 | Miscellaneous 4/0 ground wire, conducts trays and hardware | 1 | lot | 16000 | 9000 | 25000 | |
| 19 | Reconfiguration of DCS screens, and existing system | 1 | lot | | 25,000 | 25000 | |
| 20 | 25kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer | 1 | ea | 31,000 | 2,000 | 33,000 | |
| | Commissioning | | | - | 63,000 | 63,000 | |
| | Totals | | | 505,944 | 184220 | 690,164 | |

### 3.3.6 Existing Unit De-Commissioning and Demolition

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as sensitivity, then a value such as $40,000 might be used, but this would not be expected to either sway the selection of a preferred option, or impact the overall cost but rather be part of an overall project contingency regardless of any option selected.

### 3.3.7 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals.

**EPC Costs**

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be 5% of direct costs of the GT or diesel package and 10% of the balance of plant. The project management and commissioning costs (excluding fuel, Hydro staff costs) are estimated to be 7% of total direct costs. .

**Owner's Costs**

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is assumed to undertake the early steps to get its Public Utilities Board (PUB) approvals as part of its ongoing operations cost. Hydro is also assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that Owner costs could amount to on the order of 1.5% of directs or about $150,000.

### 3.3.8 Total New and Nearly New 2 x 5MW GTG Capital Cost Estimate

The total New and Nearly New 2 x 5 MW GTG cost estimate is as follows. The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

TABLE 3-10 CAPITAL COST ESTIMATE – TRANSPORTABLE GTG

**Capital Cost Comparison**
**Capital cost estimate $1,000 Can 2011**

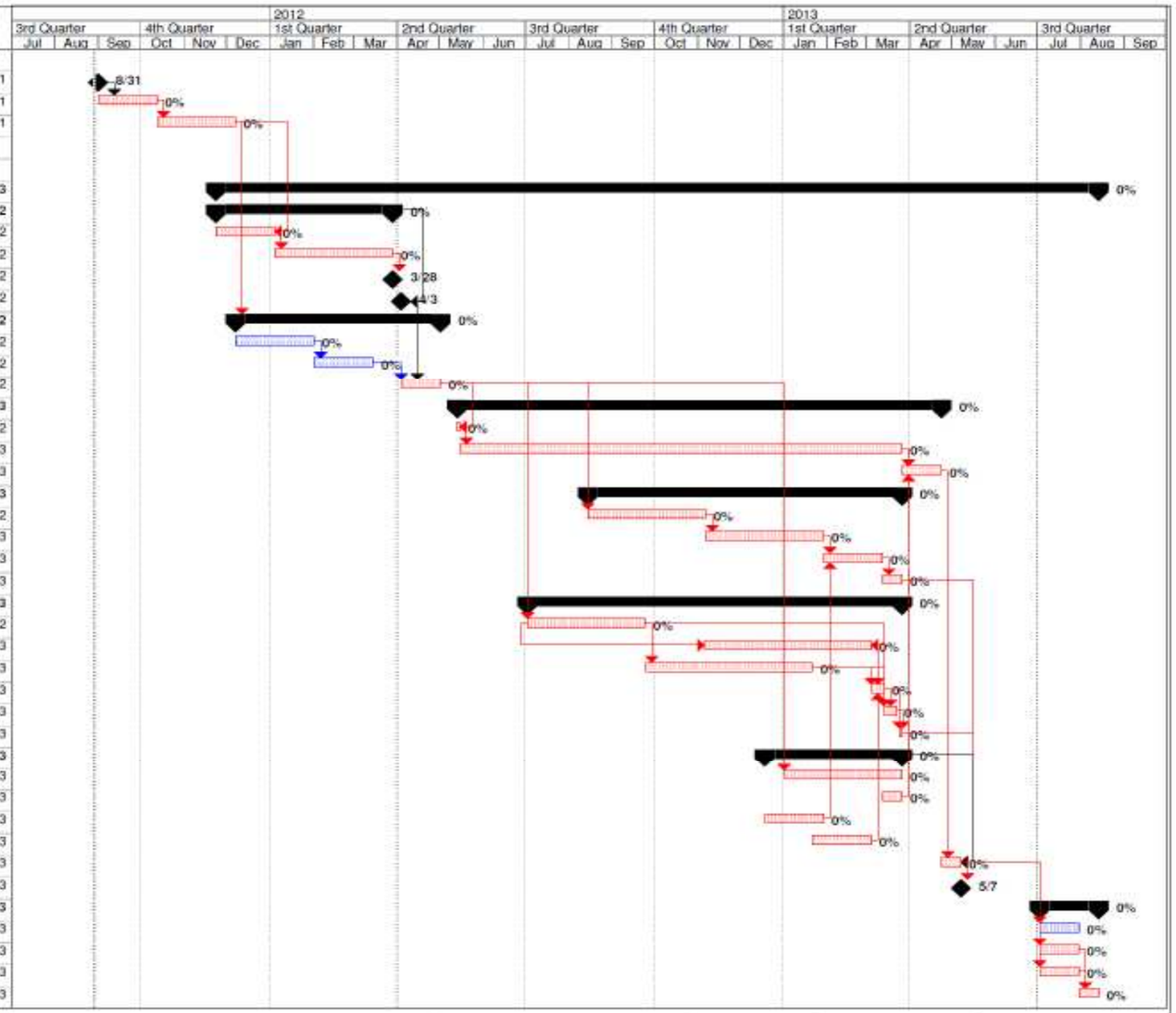
| Option Number | 1 | 1A |
|---|---|---|
| Option | New 2 x 5 MW GT | Used 2 x 5 MW GT |
| GT/Diesel Cost | $10,865 | $9,234 |
| Civil Works | $131 | $131 |
| Electrical Works | $759 | $759 |
| BOP Systems | $129 | $129 |
| Existing Unit Demolition & Removal | $7 | $7 |
| **Sub-Total - Directs and Indirects** | $11,891 | $10,260 |
| Project Engineering | $625 | $544 |
| Project Management | $832 | $718 |
| Total | $13,348 | $11,522 |

### 3.3.9 Schedule

The schedules for the new and nearly new 2 X 5 MW GTG are illustrated below. The basic schedule highlights are as follows:

| Task | New GT | Nearly New GT |
|---|---|---|
| Review of Options Report | Sept 2011 | |
| Project Approvals and Release | Sept 2011 - Dec 2011 | |
| Engineer, Procure, Construct Contract | May 2012 | |
| In-Service of New 2 x 5 MW GT | May 2013 | March 2013 |
| Decommission Existing GT | Aug/Dec 2013 | Aug/Dec 2013 |

| ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 |
| 5 | | | | |
| 6 | | | | |
| 7 | **New GT or Diesel Units** | **449 days** | **Thu 11/24/11** | **Tue 8/13/13** |
| 8 | **Project Environmental & Regulatory Approvals** | **90 days** | **Thu 11/24/11** | **Wed 3/28/12** |
| 9 | Prepare Dispersion Modelling & Submission | 30 days | Thu 11/24/11 | Wed 1/4/12 |
| 10 | Regulatory Review and Approval | 60 days | Thu 1/5/12 | Wed 3/28/12 |
| 11 | Environmental Approval | 0 days | Wed 3/28/12 | Wed 3/28/12 |
| 12 | Project Full Release | 0 days | Tue 4/3/12 | Tue 4/3/12 |
| 13 | **Request for Proposal (RFP) for Engineer procure Cons** | **104 days** | **Thu 12/8/11** | **Tue 5/1/12** |
| 14 | Prepare | 40 days | Thu 12/8/11 | Wed 2/1/12 |
| 15 | Bid | 6 wks | Thu 2/2/12 | Wed 3/14/12 |
| 16 | Award | 20 days | Wed 4/4/12 | Tue 5/1/12 |
| 17 | **New Gas Turbien or Diesel Engine Generator** | **247 days** | **Mon 5/14/12** | **Tue 4/23/13** |
| 18 | Award Gas Turbine (GT)/Engine Contract | 2 days | Mon 5/14/12 | Tue 5/15/12 |
| 19 | Manufacture & Deliver Transportable Engines | 45 wks | Wed 5/16/12 | Tue 3/26/13 |
| 20 | Install and Commission | 4 wks | Wed 3/27/13 | Tue 4/23/13 |
| 21 | **Fuel System** | **160 days** | **Wed 8/15/12** | **Tue 3/26/13** |
| 22 | Engineer | 12 wks | Wed 8/15/12 | Tue 11/6/12 |
| 23 | Order, Manufacture, Deliver | 12 wks | Wed 11/7/12 | Tue 1/29/13 |
| 24 | Install new fuel lines and receiving system | 6 wks | Wed 1/30/13 | Tue 3/12/13 |
| 25 | Commission System | 2 wks | Wed 3/13/13 | Tue 3/26/13 |
| 26 | **Electrical & Control Systmes** | **191 days** | **Tue 7/3/12** | **Tue 3/26/13** |
| 27 | Engineer | 12 wks | Tue 7/3/12 | Mon 9/24/12 |
| 28 | Order & Manufacture Elect & Control (E&C) Equip | 17 wks | Tue 11/6/12 | Mon 3/4/13 |
| 29 | Electrical Building Manufacture, Delivery, Install | 17 wks | Tue 9/25/12 | Mon 1/21/13 |
| 30 | Install New System | 7 days | Tue 3/5/13 | Wed 3/13/13 |
| 31 | RE-align Existing Plant Systems | 7 days | Thu 3/14/13 | Fri 3/22/13 |
| 32 | Commission unit | 2 days | Mon 3/25/13 | Tue 3/26/13 |
| 33 | **Site Civil Work** | **70 days** | **Wed 12/19/12** | **Tue 3/26/13** |
| 34 | Engineer | 12 wks | Wed 1/2/13 | Tue 3/26/13 |
| 35 | Generator area clearing and civil | 2 wks | Wed 3/13/13 | Tue 3/26/13 |
| 36 | Fuel line civil work | 6 wks | Wed 12/19/12 | Tue 1/29/13 |
| 37 | Electrical an contro cable civil work | 6 wks | Tue 1/22/13 | Mon 3/4/13 |
| 38 | Complete Unit Test | 10 days | Wed 4/24/13 | Tue 5/7/13 |
| 39 | Gas Turbine (GT) In-Service (I/S) | 0 days | Tue 5/7/13 | Tue 5/7/13 |
| 40 | **Decommission Existing GT** | **30 days** | **Wed 7/3/13** | **Tue 8/13/13** |
| 41 | Fuel delivery system | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 42 | Electrical & Controls | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 43 | GT | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 44 | Building | 2 wks | Wed 7/31/13 | Tue 8/13/13 |



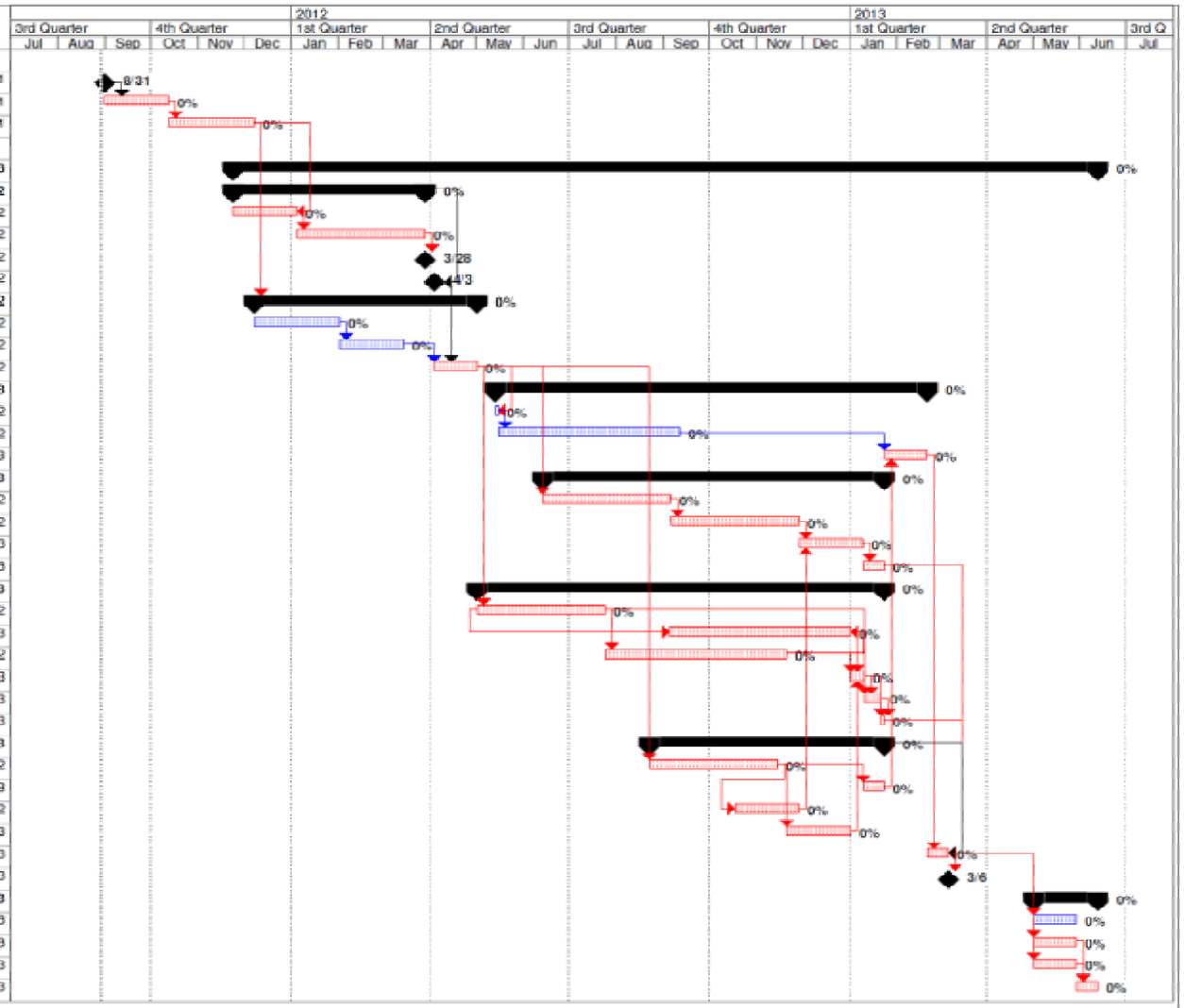

Project: Project1 New.mpp
Date: Mon 8/29/11

Critical, Critical Split, Critical Progress, Task, Split, Task Progress, Baseline, Baseline Split, Baseline Milestone, Milestone, Summary Progress, Summary, Project Summary, External Tasks, External Milestone, Deadline

Page 1

**FIGURE 3-3 SCHEDULE – NEW TRANSPORTABLE 2 X 5 MW GTG**

| ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 |
| 5 | | | | |
| 6 | **Nearly New gas Turbine (GT) or Diesel Generator Units** | **405 days** | **Thu 11/24/11** | **Wed 6/12/13** |
| 7 | **Project Environmental & Regulatory Approvals** | **90 days** | **Thu 11/24/11** | **Wed 3/28/12** |
| 8 | Prepare Dispersion Modelling & Submission | 30 days | Thu 11/24/11 | Wed 1/4/12 |
| 9 | Regulatory Review and Approval | 60 days | Thu 1/5/12 | Wed 3/28/12 |
| 10 | Environmental Approval | 0 days | Wed 3/28/12 | Wed 3/28/12 |
| 11 | Project Full Release | 0 days | Tue 4/3/12 | Tue 4/3/12 |
| 12 | **Request for Proposal (RFP) for Engineer/Procure/Construct (** | **104 days** | **Thu 12/8/11** | **Tue 5/1/12** |
| 13 | Prepare | 40 days | Thu 12/8/11 | Wed 2/1/12 |
| 14 | Bid | 6 wks | Thu 2/2/12 | Wed 3/14/12 |
| 15 | Award | 20 days | Wed 4/4/12 | Tue 5/1/12 |
| 16 | **Nearly New GT or Diesel Engine Generator** | **203 days** | **Mon 5/14/12** | **Wed 2/20/13** |
| 17 | Award GT/Diesel Engine Contract | 2 days | Mon 5/14/12 | Tue 5/15/12 |
| 18 | Manufacture & Deliver Transportable Engines | 17 wks | Wed 5/16/12 | Tue 9/11/12 |
| 19 | Install and Commission | 4 wks | Thu 1/24/13 | Wed 2/20/13 |
| 20 | **Fuel System** | **160 days** | **Thu 6/14/12** | **Wed 1/23/13** |
| 21 | Engineer | 12 wks | Thu 6/14/12 | Wed 9/5/12 |
| 22 | Order, Manufacture, Deliver | 12 wks | Thu 9/6/12 | Wed 11/28/12 |
| 23 | Install new fuel lines and receiving system | 6 wks | Thu 11/29/12 | Wed 1/9/13 |
| 24 | Commission System | 2 wks | Thu 1/10/13 | Wed 1/23/13 |
| 25 | **Electrical & Control Systmes** | **191 days** | **Wed 5/2/12** | **Wed 1/23/13** |
| 26 | Engineer | 12 wks | Wed 5/2/12 | Tue 7/24/12 |
| 27 | Order & Manufacture Elect & Control (E&C) Equip | 17 wks | Wed 9/5/12 | Tue 1/1/13 |
| 28 | Electrical Building Manufacture, Delivery, Install | 17 wks | Wed 7/25/12 | Tue 11/20/12 |
| 29 | Install New System | 7 days | Wed 1/2/13 | Thu 1/10/13 |
| 30 | RE-align Existing Plant Systems | 7 days | Fri 1/11/13 | Mon 1/21/13 |
| 31 | Commission unit | 2 days | Tue 1/22/13 | Wed 1/23/13 |
| 32 | **Site Civil Work** | **110 days** | **Thu 8/23/12** | **Wed 1/23/13** |
| 33 | Engineer | 12 wks | Thu 8/23/12 | Wed 11/14/12 |
| 34 | Generator area clearing and civil | 2 wks | Thu 1/10/13 | Wed 1/23/13 |
| 35 | Fuel line civil work | 6 wks | Thu 10/18/12 | Wed 11/28/12 |
| 36 | Electrical an contro cable civil work | 6 wks | Wed 11/21/12 | Tue 1/1/13 |
| 37 | Complete Unit Test | 10 days | Thu 2/21/13 | Wed 3/6/13 |
| 38 | GT In-Service (I/S) | 0 days | Wed 3/6/13 | Wed 3/6/13 |
| 39 | **Decommission Existing GT** | **30 days** | **Thu 5/2/13** | **Wed 6/12/13** |
| 40 | Fuel delivery system | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 41 | Electrical & Controls | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 42 | GT | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 43 | Building | 2 wks | Thu 5/30/13 | Wed 6/12/13 |




Project: Project1 Nearly New.mpp
Date: Mon 8/29/11

Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

Page 1

**FIGURE 3-4 SCHEDULE – NEARLY NEW/USED TRANSPORTABLE 2 X 5 MW GTG**

### 3.3.10 OMA Cost Estimate to 2020

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The operating costs shown are the same for both the new and nearly new cases. For the type of operation required, peak and emergency operation (typically <=60 Hrs/Yr, the GT packages normally would require only an annual service and inspection by qualified service personnel. Most utilities would exercise the equipment once a month to verify proper operation.

The costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The vendor indicated that for the 6 month inspection the cost was to be $10,000 and for the yearly it was $18,000 and that these costs would be the same for both new and nearly new. A lower value was actually used reflecting their very limited use – essentially an annual inspection similar to what is done now.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on receiving the same value per MWh as the existing units would if they were to recover their fuelling costs plus marginal operating and maintenance costs. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

**TABLE 3-11 NEW GTG OMA COST ASSUMPTIONS**

**Assumptions**

| | | |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 12,000 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,031 |
| Electricity Value (E) = Value for existing GT | $/MWh | $343.25 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

**TABLE 3-12 NEW GTG OMA COSTS**

New/Near New GT
1000's Cnd $ - 2011/Yr

| | Maintenance | Operations | Fuelling | Sub-Total | Electricity Value | | Total |
|---|---|---|---|---|---|---|---|
| 2012 | $15 | $0 | $0 | $15 | $0 | | $15 |
| 2013 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2014 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2015 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2016 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2017 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2018 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2019 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2020 | $0 | $40 | $155 | $195 | ($206) | | ($11) |
| TOTAL | $155 | $323 | $1,237 | $1,714 | ($1,648) | | $67 |

## 3.4 Option 2 – 5 x 2 MW Diesel Engine Generator (DG) at 13.8kV (New and Nearly New Option)

### 3.4.1 Description

In this option, five 2 MW diesel engine generator units would be utilized to provide black start capability. Sizing at 2 MW each would allow the units to be more transportable than larger units. In addition, this is approximately the maximum size available for portable units. With this arrangement, all five of the units would be required to operate simultaneously to provide sufficient power for black start. A generator voltage of 13.8 kV connected to the delta primary of the existing T9 transformer would be utilized. Other units from Cummins Diesel are available as packaged two 1 MW units. However, NL Hydro expressed reliability and operational concerns with 10 diesel units and they have not been considered further.

Vendor information was received from TOROMONT CAT. These will be mobile units supplied by a vendor and will not require a diesel building. Several items will however be required, such as:

- Turbine trailers areas with site work to ensure sufficient ground support for the mobile diesel genset units.
- A pre-engineered shelter for electrical equipment, including concrete foundation and floor slab. Approximately 30 ft x 30 ft.
- A reinforced concrete pipe/trench for cables running from the diesel gensets to the main building and from the diesel gensets to the existing fuel lines.
- Electrical and I&C connections to the existing plant facilities

### 3.4.2 Connections to the Existing E and C System

Each diesel/generator unit will be a completely self contained unit capable of operating in isochronous or droop mode, having its own main breaker (52), AVR, control and protection, synchronizing, load sharing, paralleling, monitoring and ability to connect to the existing station DCS.

All these functions will connect to a new building. Each generator output breaker will be cabled to an item of isolating switchgear. The isolating switchgear will consist of five (5) 13.8 kV disconnect switches, one (1) fused disconnect for auxiliaries, and one disconnect for connection of the zig-zag grounding transformer.

An isolation switch allows the individual GT unit to be taken out of service at any time. Each generator breaker (52) is synchronized for connection to the station service bus through the 13.8 kV:4160 V transformer (T9), either individually or as any combination of generators.

The five DG units will be designed with high resistance grounding consisting of a grounding transformer and NGR to limit the ground fault current to less than 10 A as normal standard.

The 13.8KV fused disconnect fused switch #1 (FSWI) will feed a 112 kVA, 13.8 kV:575 V, 3 phase transformer to provide 600 V service via a new 600 A, 600 V, 3phase, 60 Hz, 3 W MCC. The MCC will typically provide starters or fused disconnects for pumps, hearing, 120/208 V distribution via a 30 kVA transformer and the battery charger. The battery charger supplies the 129 VDC battery and distribution.

Alternative supplies to the MCC will be via an automatic transfer switch (ATS) and a manual transfer switch (MTS) and will be from the diesel bus DB34 and power center 'C', both located in the powerhouse.

Protection & Control/DCS interfaces will combine the requirements of the new units with the requirements of the existing T9 transformer and 4160 V breaker SSB2.

#### 3.4.2.1.1 Changes to Existing EI&C Systems

The existing protection, control and DCS cables entering the present GT building will be pulled-back and terminated in a weatherproof JB. New teck cables will be connected to these existing cables and direct-buried from the JB to the P&C/DCS interface in the new building.

Similarly the 600 V feeds from the diesel bus DB34 and power centre 'C' will be pulled-back and terminated in weatherproof JB's. New teck cables will be connected to these existing cables and direct-buried from the JB's to the MTS in the new 'building'.

All new weatherproof JB's will be mounted above ground.

Power cable from the common bus of the isolating switchgear to the existing T9 transformer will replace the existing cables, and will be direct-buried from T9 to the switchgear.

Changes will be made as necessary to P&C in Panel 13 (in the powerhouse) and also in Panel 2 (in the powerhouse). Screens will be reconfigured in the control room involving the five new units and their monitoring, control, indication, and alarm functions.

### 3.4.3 Performance Characteristics

Diesel gensets have several ratings.

> Standby – Applicable for supplying continuous electrical power (at variable load) in the event of a utility power failure. No overload is permitted on these ratings. The generator on the generator set is peak prime rated (as defined in ISO8528-3) at 30° C (86° F).
>
> Prime – Applicable for supplying continuous electrical power (at variable load) in lieu of commercially purchased power. There is no limitation to the annual hours of operation and the generator set can supply 10% overload power for 1 hour in 12 hours.

NL Hydro noted that for blackstart only, their requirement is for the standby rating. Information on prime is provided for comparison.

**TABLE 3-13 DIESEL PERFORMANCE CRITERIA**

| Generator Set Technical Data | Units | 60 Hz Prime | 60 Hz Standby |
|---|---|---|---|
| Performance Specification | | DM8264 | DM8264 |
| Power Rating | kW (kVA) | 1825 (2281) | 2000 (2500) |
| Lubricating System<br>Oil pan capacity | L (gal) | 401.3 (106) | 401.3 (106) |
| Fuel System<br>Fuel Consumption<br>100% load<br>75 % load<br>50 %load<br>Fuel tank capacity<br>Running time @ 75% rating | <br>L (gal)<br>L (gal)<br>L (gal)<br><br>L (gal)<br>Hours | <br><br>483.2 (127.6)<br>380 (100.4)<br>270.5 (71.5)<br>4731 (1,250)<br>12.5 | <br><br>525.7 (138.9<br>408.2 (107.8)<br>294.2 (77.7)<br>4731 (1,250)<br>11.5 |
| Cooling System<br>Radiator coolant capacity including engine | L (gal) | 630 (166) | 630 (166) |
| Air Requirements<br>Combustion air flow<br>Maximum air cleaner restriction<br>Generator cooling air | m3/min (cfm)<br>kPa (in H2O)<br>m3/min (cfm) | 174.7 (6169)<br>6.2 (24.9)<br>168 (4,995) | 180.3 (6367)<br>6.2 (24.9)<br>168 (4,995) |
| Exhaust System<br>Exhaust flow at rated kW<br>Exhaust stack temperature at rated kW dry exhaust | m3/min (cfm)<br>℃ (℉) | 404 (14,260)<br>387 (728) | 428.6 (15,137)<br>405 (762) |
| Noise Rating (with enclosure)<br>@ 7 meters (23 feet)<br>@15 meters (50 feet) | dB(A)<br>dB(A) | 78<br>74 | 79<br>75 |

### 3.4.3.1 Emission Requirements

For new diesel units on oil, the requirement is uncertain. In the United States, the United States Environmental protection Agency (USEPA) is clearly moving to even tighter diesel genset limits. Canada has only adopted those for mobile (on-road) sources, not stationary sources. There is also the issue of emergency use (black-start would apply) and non-emergency (distribution support, grid support is likely to apply):

- For stationary (including transportable genset units) in emergency use (i.e. black start only)
  - In US would likely be a USEPA Tier 2 (a diesel requiring advanced combustion systems)
  - In Canada, no specific regulations could be identified. Diesel units are likely similar to those required in the US, or comparable to the Canadian guideline requirement for gas turbines above

- For stationary (including transportable genset) in a non-emergency use (i.e. distribution support).
  - In the US, a USEPA Tier 4 (a diesel unit required to have advanced combustion and post combustion control such as selective catalytic reduction (SCR) using ammonia or urea and would also require ultralow sulphur diesel fuel (15 ppm sulphur)
  - In Canada, no specific regulations identified – the study assumes for the role required that Tier 2 would suffice. A question may arise where the plan is for their use in distribution system support. This should likely be considered an emergency role and not result in more onerous restrictions. At worst, assuming a requirement comparable to that for gas turbines above for peaking purposes is reasonable.

Operating time limits could be placed on peaking units. An emergency unit for black start only might be exempt, but could thereby limit its future.

No specific diesel genset applicable to Newfoundland air pollution regulations were identified. There is however a general requirement for BACT, with provisions for an exemption based on economics and on a ministerial exemption for practical purposes.

In emergency and non-emergency applications, dispersion modeling is likely required to demonstrate ground level concentrations are acceptable.

#### 3.4.3.2 Transition

The existing gas turbine system is to remain active while the new system is independently installed. A short outage will be required during a transition period during which final connections to the electrical, instrumentation and controls, and fuel systems are made.

#### 3.4.3.3 Decommissioning

The existing GT unit will be decommissioned, including those parts of the fuel system and electrical connections not required for the new units. This will occur once the new transportable units are in place and operational. A modified fuel offloading/receiving system will remain.

### 3.4.4 General Arrangement Sketch

See attached GA sketch based on dimensional information provided by TOROMONT CAT (APPENDIX 3).

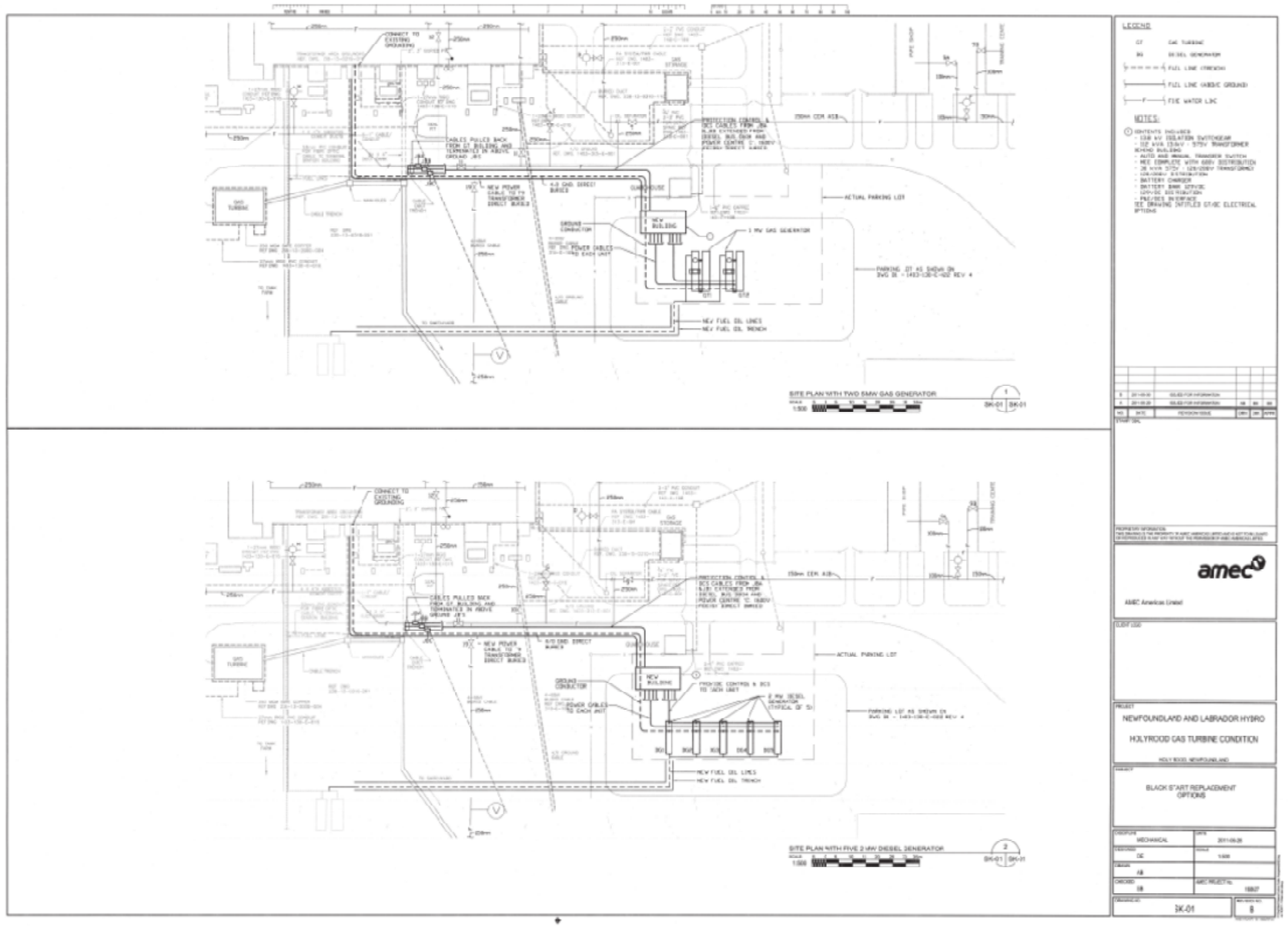



**FIGURE 3-5 GENERAL ARRANGEMENT – 5 X 2 MW DIESEL GENSETS**



### 3.4.5 Capital Cost Estimate (Differentiate New and Nearly New Option)

Budget pricing supplied by CAT indicated that the transportable diesel genset cost would be in the order of $1,500,000.00 per unit. However, there could be a 50% increase in price if the units are required to meet more stringent emission limits in emission regulations likely to be adopted soon by the federal government. AMEC has requested this information but as not received any additional details on these requirements, and their applicability to this application for black start capability and short term distribution system maintenance support.

There is not expected to be a significant difference in price between the New and Nearly New options. The advantage between these options is the possibility that a Nearly New set of units will be available and lead/delivery times are significantly reduced.

**TABLE 3-14 DIESEL GENSET CAPITAL COST**

| Item | Description | Unit Price | Quantity | Cost |
|---|---|---|---|---|
| 1. | XQ2000 with 13.8kv output $1.5m per unit (x5) under current emissions rules. | $1,500,000 | 5 | $7,500,000 |
| 2. | Commissioning Parts, Start-up, and Site Testing | $20,000 | 5 | $100,000 |
| 4 | Shipping | $25,000 | 5 | $125,000 |
| 5 | Training | $5,000 | 5 | $25,000 |
| 6 | Marine Grade Filter (Included) | | | |
| | | | | $7,750,000 |

- Duties and taxes not included in estimate.
- This quote is provided for budgetary purposes only and does not represent a firm quote.

#### 3.4.5.1 Diesel Trailer Units

**TABLE 3-15 DIESEL PACKAGE COMPONENTS**

| Component | Description |
|---|---|
| Engine | ▪ EPA approved Tier 2 3516C Caterpillar engine<br>▪ Heavy duty air cleaner with service indicator<br>▪ 60-Amp charging alternator<br>▪ Fuel filters – primary and duplex secondary with integral water separator and change-over valve<br>▪ Lubricating oil system with spin-on, full flow oil filters and water cooled oil cooler<br>▪ Oil drain lines routed to engine rail<br>▪ Jacket water heater<br>▪ Fuel cooler and priming pump<br>▪ Electronic ADEM™ A3 controls<br>▪ 24V electric starting motors with battery rack and cables |

| Component | Description |
|---|---|
| | ▪ 110% spill containment of onboard engine fluids |
| Generator | ▪ SR-4B brushless, permanent magnet excited, three-phase with Caterpillar digital voltage regulator (CDVR),space heater, 6-lead design, Class H insulation operating at Class F temperature for extended life,<br>▪ winding temperature detectors and anti-condensation space heaters (120/240 V 1.2 kW) |
| Containerized Module | ▪ 40' ISO high cube container, CSC certified<br>▪ 3-axle, 40' ISO container chassis<br>▪ Seven (7) sound attenuated air intake louvers and 4 lockable personnel doors with panic release<br>▪ Side bus bar access door, external access load connection bus bars<br>▪ Shore power connection via distribution block connections for jacket water heater, battery charger, space heaters, and generator condensate heaters<br>▪ Standard lighting 3 AC/4 DC, one (1) single duplex service receptacle, 2 external break-glass emergency stop push buttons<br>▪ 1,250 gal fuel tank, UL listed, double wall, 9 hr runtime @ prime rating<br>▪ Sound attenuated 75 dB(A) @ 50 ft<br>▪ Spill containment 110% of all engine fluids<br>▪ Four (4) oversized maintenance-free batteries, battery rack and 20-Amp battery charger<br>▪ Hospital grade, internally insulated, rectangular exhaust silencer with vertical discharge<br>▪ Vibration isolators, corrosion resistant hardware and hinges<br>▪ External drain access to standard fluids<br>▪ Fire extinguishers (Qty 2)<br>▪ Standard Cat rental decals and painted standard Cat power module white<br>▪ Interior walls and ceilings insulated with 100 mm of acoustic paneling<br>▪ Floor of container insulated with acoustic glass and covered with galvanized steel |
| Cooling | ▪ Standard cooling provides 43° C ambient capability (60 Hz) at prime +10% rating<br>▪ Vertically mounted, separate ATAAC and JW cores with vertical air discharge |

| Component | Description |
|---|---|
| Generator Paralleling Control | ▪ Custom switchgear control with EMCP 3.3 genset mounted controller and wall mounted paralleling controls Provides single unit and/or multi-unit/utility paralleling components. Standby, load sense/load demand, import, export, and base load modes. Comes standard with Basler Utility Multi-function Relay IPS-100.<br>▪ Exclusive Caterpillar Digital Voltage Regulator (CDVR) Three-phase sensing and adjustable Volts-per- Hertz regulation give precise control, excellent block loading, and constant voltage in the normal operating range.<br>▪ Automatic start/stop with cool down timer<br>▪ Protections: 25, 27/59, 40, 32, 81 O/U<br>▪ Utility multi-function relay protections: 25,27/59, 32, 47, 50/51, 62, 67, 81 O/U<br>▪ UMR is IEEE1547-2003 compliant in most applications<br>▪ Reverse compatibility module provided for interface to legacy power modules<br>▪ Touch screen controls with event log<br>▪ Multi-mode operation (island, multi-island and utility parallel), load sharing (multi-unit only)<br>▪ Import & export control (utility parallel only), manual and automatic paralleling capability<br>▪ Touch screen display (status and alarms)<br>▪ Metering display: voltage, current, frequency, power factor, kW, WHM, kVAR, and synchroscope |
| Quality | ▪ Standard genset and package factory tested<br>▪ UL, NEMA, ISO and IEEE standards |
| Other | |

### 3.4.5.2 Site Civil Works – Trailer Site and Electrical & Gas Connections

Site/civil works requirements are primarily related to the diesel generator trailer site, and to electrical and fuel connections. The major costs are expected to be:

- Confirming the bearing capacity of soil = $4,000
- Pre-engineered shelter for elec. equipment = $45,000
- Concrete cable trench = $70,000

Oil piping excavation is included in the cost of the piping.

### 3.4.5.3 Existing Gas Turbine Generator Unit Modifications

For this application the gas turbine units should be provided with air filter media suitable for use in a marine environment as well as have coatings on external components designed for such environments.

### 3.4.5.4 New Diesel Genset Mechanical Requirements

Aside from fuel oil supply, it is expected that the diesel genset units would be self contained and not require any additional mechanical equipment. Specific to diesel engine trailers, each trailer must have 15.6 m clearance on both sides to ensure adequate ventilation and combustion airflow.

**Connection to Fuel Oil System and Changes to Existing Oil System**

From supplier information each turbine at its maximum output would consume fuel at a rate of 2.3 gpm (8.7 L/min). This implies for black start with five units running there would be a total of 11.5 gpm (43.5 L/min). For a 24 hour period, the fuel oil storage requirement would be about 16,500 gallons (62, 459 L) of fuel. The current fuel oil tanks as previously noted are 26,417 gal (100,000 L) each.

The new diesel units will be located approximately 160 m away from the existing GT building and will require new fuel oil supply and return piping from the existing system. Since five diesels would be provided under this option, it is anticipated that five connections would be required. Due to spacing requirements of the diesels gen sets this manifold system would be quite extensive. Piping could be routed through a trenched containment system. Preliminary sizing indicates that the supply and return lines would be 3 inch with a total length of 130 m each.

**TABLE 3-16 DIESEL GENSET – MECHANICAL SYSTEM COSTS**

| Item | Cost |
|---|---|
| 3” supply and return fuel line | $77,100.00 |
| Project Engineering Costs Mechanical | $15,000.00 |

### 3.4.6 New Diesel Genset Option – Electrical, Instrumentation, and Control Requirements

With generators connected directly to the 4160 V bus which is normally fed from the grid, the three-phase short circuit current contribution from the grid (to the internal fault near the line end of the generator winding) is significant which results in more damage to the generator windings.

With the 5 X 2 MW generators, the calculated voltage drop at the 4160 V bus results are improved, but potential drawbacks are expected as follows:

1. The starting reliability of 5 generators (following total loss of station AC supply) is questionable. The successful starting of 5 units is not easy to achieve. With our experience of multiple diesel starting at once, there is a high probability that 100% success is not easily achieved compared to two 5 MW units on the assumption that one 5 MW unit is suitable for plant essential loads.

2. The isochronous load sharing of 5 units requires 5 electronic governors and a complicated master controller. This is necessary to manage the paralleling operation of 5 units during isochronous mode, particularly during starting of MV motors. This will cost more.

3. With the same contribution of fault current from the grid through the I0 MVA step-down transformer, may exceed the damaging level of the 2 MW generator for internal fault of the stator (close to line end of windings).

4. The 13.8 kV switchgear line-up would be much larger than the 2 X 5 MW option.

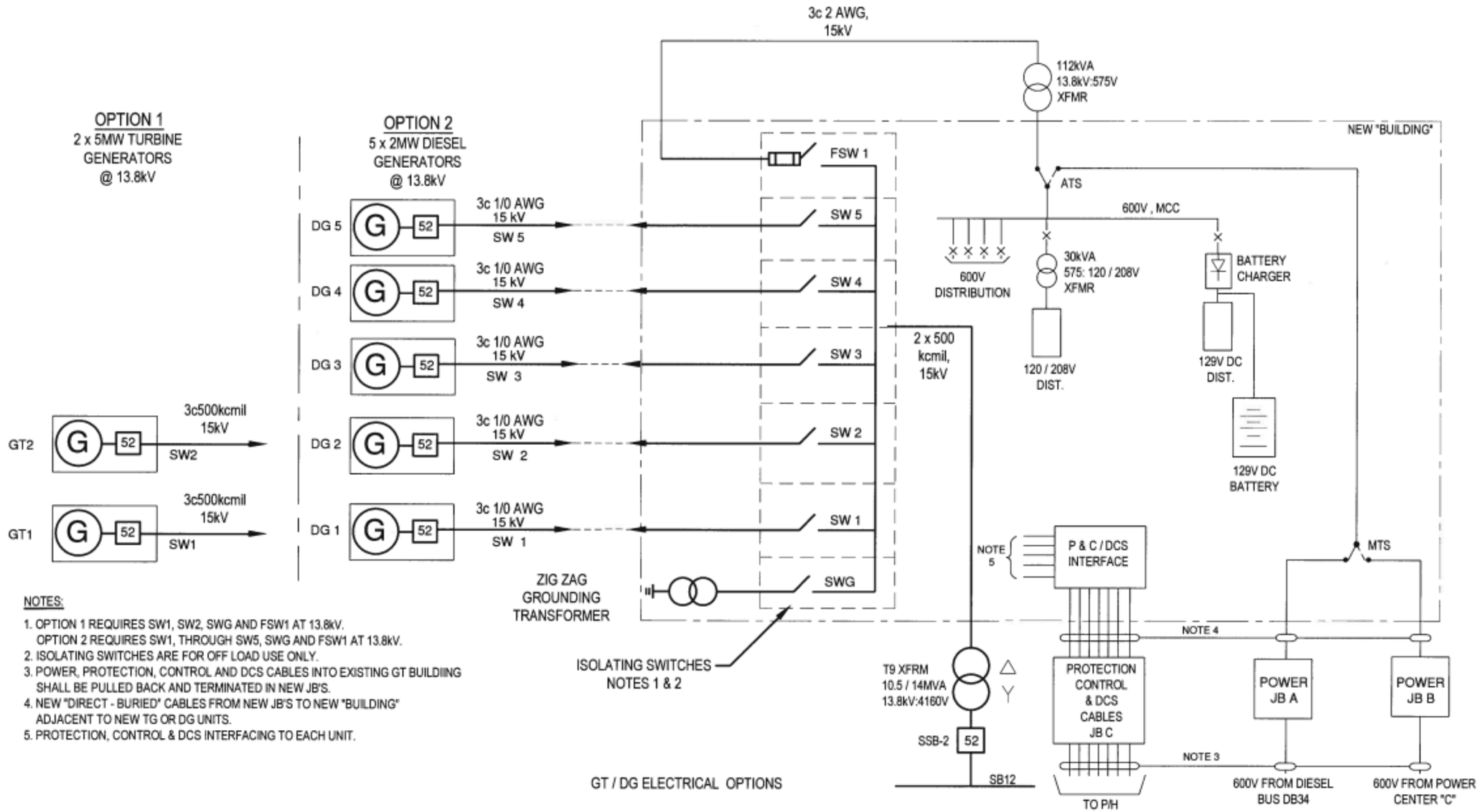



**FIGURE 3-6 SINGLE LINE SKETCH – NEW DIESEL GENSET**

### 3.4.6.1 Equipment & Installation Costs – Electrical & Controls

**TABLE 3-17 ELECTRICAL & CONTROL EQUIPMENT AND INSTALLATION COSTS (OPTION 2) – 5 X 2 MW TGS @ 4160 V.**

| Item # | Desciption | Qty | Unit | Material | Labour | Total | Comments |
|---|---|---|---|---|---|---|---|
| 1 | 3c500 kemil, Teck 15kV cable (2 runs) | 440 | m | 90,200 | 10,000 | 100,200 | Power from switchgear to generators T9 and grounding transformer |
| 2 | 3C 1/0 AWG Teck 15kV cable | 300 | M | 10,800 | 4,000 | 14,800 | |
| 3 | 13.8kV isolating switchgear (6+1 fused switch) | 1 | ea | 144700 | 15000 | 159,700 | |
| 4 | P&C/DCS interface | 1 | ea | 65,000 | 10,000 | 75,000 | Will contain interfacing requirements of the new units to T9 and SSB2 |
| 5 | 10 x 3c12AWG, Teck, 1000V cable | 500 | m | 1920 | 4500 | 6420 | from P&C/DCS interface to DG1 through DG5 for protection and control |
| 6 | 2 x 24c16AWG, Teck, 1000V cable | 350 | m | 8505 | 3150 | 11,655 | Cables from P&C/DCS interface to junction box JBC |
| 7 | 4 x 4c12AWG, Teck, 1000V cable | 700 | m | 3290 | 6300 | 9590 | Cable from FSWI to 112kV transformer |
| 8 | 1 x 12C12AWG, Teck, 1000V cable | 175 | m | 2240 | 1575 | 3815 | Cable ATS to MTS and JBA/JBB to MTS |
| 9 | 3c2AWG, Teck, 15kV cable | 15 | m | 945 | 135 | 1080 | |
| 10 | 2 x 3c1/0, Teck, 1000V cable | 125 | m | 4500 | 1125 | 5625 | |
| 11 | 112kVA, 13.8kV:575V, 3ph, 60Hz transformer | 1 | ea | 30000 | 3000 | 33000 | |
| 12 | 200A, 600V, 3ph, 60Hz automatic transfer switch | 1 | ea | 5336 | 1500 | 6836 | |
| 13 | 200A, 600V, 3ph, 60Hz manual transfer switch | 1 | ea | 2000 | 1000 | 3000 | |
| 14 | MCC, 600A, 600V, 3ph, 3W | 1 | ea | 30000 | 5000 | 35000 | |
| 15 | 30kVA, 575:120/280V, 3ph, 60Hz transformer | 1 | ea | 1,000 | 500 | 1,500 | |
| 16 | 129VDC distribution panel, motor starters and disconnects | 1 | ea | 35000 | 6500 | 41500 | |
| 17 | 100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers | 1 | ea | 1418 | 350 | 1768 | |
| 18 | 600V, battery charger, 129VDC output | 1 | ea | 16,000 | 3220 | 19,220 | |
| 19 | 129VDC battery bank | 1 | ea | 39,000 | 7500 | 46,500 | |
| 20 | All interconnecting cabling | 1 | lot | 16000 | 12000 | 28000 | Includes MCC feeders, heating and lighting |
| 21 | Miscellaneous 4/0 ground wire, tray and hardware | 1 | lot | 16000 | 9000 | 25,000 | |
| 22 | Reconfiguration of DCS screens, and existing system | 1 | lot | - | 25,000 | 25,000 | |
| 23 | 25 kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer | 1 | ea | 31,000 | 2,000 | 33,000 | |
| 24 | Commissioning | | | - | 69,000 | 69,000 | |
| | Totals | | | 554,854 | 201,355 | 756,209 | |

### 3.4.7 Existing Unit De-Commissioning and Demolition

No significant incremental costs were identified for existing unit de-commissioning and/or demolition. It was felt that the value of the materials derived from the demolition could offset the cost to the contractor. If required as a sensitivity, then a value such as $40,000 might be used. This would not be expected to either sway the selection of a preferred option or impact the overall cost. It should be considered as part of an overall project contingency regardless of any option selected.

### 3.4.8 Project Engineering and Management, Owner's Costs

It was assumed that the facility implementation would be undertaken largely as an engineer, procure, construct (EPC) external contract. NL Hydro would be responsible for getting the project approved and the necessary environmental and regulatory approvals.

**EPC Costs**

For the EPC contractor, the project engineering and management costs are based on the total project costs and a percentage for engineering and for management. For the purposes of this estimate, the engineering costs are estimated to be 5% of direct costs of the GT or diesel package and 10% of the balance of plant. The project management and commissioning costs (excluding fuel, Hydro staff costs) are estimated to be 7% of total direct costs. .

**Owner's Costs**

Owner's costs are not included in the estimates, but are likely to be comparable regardless of the selected option. NL Hydro is also assumed to undertake all the necessary environmental and regulatory permitting entirely internally or with some measure of external support (i.e. environmental modeling and engineering support, or full external scope). This cost is also not included but likely on the order of $55,000.

For the actual project implementation, the assumption is that NL Hydro would assume its own costs of this initial development and then assign a project manager for the life of the project to monitor and assure its successful completion. These and other NL Hydro costs (insurance, legal, supply chain, interest, owners' contingency, Holyrood station participation, commissioning fuel, commissioning labour) are not identified or included herein. It is likely that Owner costs could amount to on the order of 1.5% of directs or about $150,000.

### 3.4.9 Total New and Nearly New 5 x 2MW Diesel Generator Capital Cost Estimate

The total New and Nearly New 5 x 2 MW diesel generator cost estimate is as follows. The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

TABLE 3-18 CAPITAL COST ESTIMATE – TRANSPORTABLE DIESEL GENSET

**Capital Cost Comparison**
**Capital cost estimate $1,000 Can 2011**

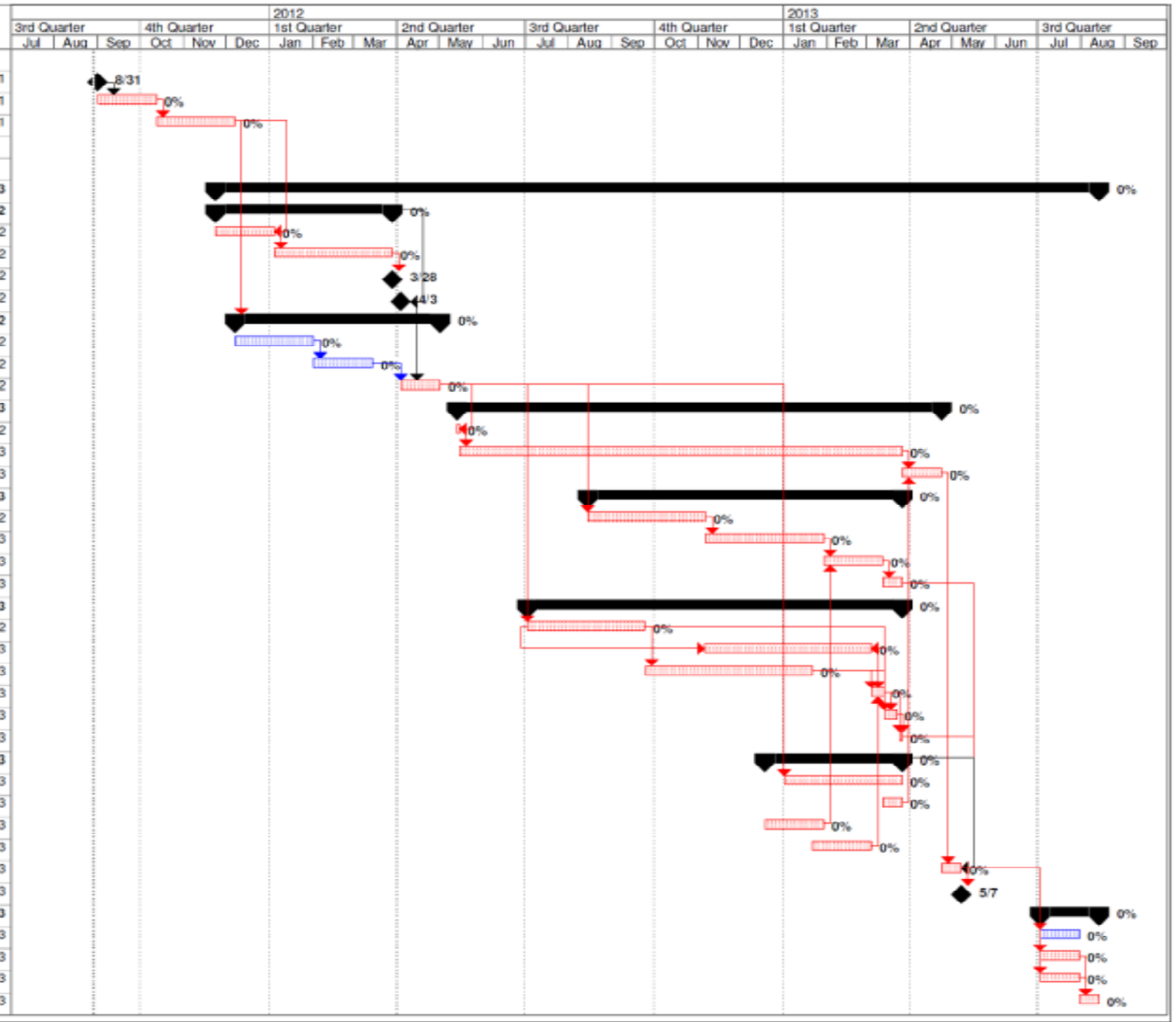
| Option Number | 2 | 2A |
|---|---|---|
| Option | New 5 x 2 MW Diesel | Used 5 x 2 MW Diesel |
| GT/Diesel Cost | $8,553 | $7,453 |
| Civil Works | $131 | $131 |
| Electrical Works | $801 | $801 |
| BOP Systems | $129 | $129 |
| Existing Unit Demolition & Removal | $7 | $7 |
| **Sub-Total - Directs and Indirects** | $9,620 | $8,520 |
| Project Engineering | $513 | $458 |
| Project Management | $673 | $596 |
| Total | $10,807 | $9,575 |

### 3.4.10 Schedule

The schedules for the new and nearly new five 2 MW diesel generator are illustrated below. The basic schedule highlights are as follows:

| Task | New Diesel Genset | Nearly New Diesel Genset |
|---|---|---|
| Review of Options Report | Sept 2011 | |
| Project Approvals and Release | Sept 2011 - Dec 2011 | |
| Engineer, Procure, Construct Contract | May 2012 | |
| In-Service of New 2 x 5 MW GT | May 2013 | March 2013 |
| Decommission Existing GT | Aug/Dec 2013 | Aug/Dec 2013 |

| ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 |
| 5 | | | | |
| 6 | | | | |
| 7 | **New GT or Diesel Units** | **449 days** | **Thu 11/24/11** | **Tue 8/13/13** |
| 8 | **Project Environmental & Regulatory Approvals** | **90 days** | **Thu 11/24/11** | **Wed 3/28/12** |
| 9 | Prepare Dispersion Modelling & Submission | 30 days | Thu 11/24/11 | Wed 1/4/12 |
| 10 | Regulatory Review and Approval | 60 days | Thu 1/5/12 | Wed 3/28/12 |
| 11 | Environmental Approval | 0 days | Wed 3/28/12 | Wed 3/28/12 |
| 12 | Project Full Release | 0 days | Tue 4/3/12 | Tue 4/3/12 |
| 13 | **Request for Proposal (RFP) for Engineer/procure/Cons** | **104 days** | **Thu 12/8/11** | **Tue 5/1/12** |
| 14 | Prepare | 40 days | Thu 12/8/11 | Wed 2/1/12 |
| 15 | Bid | 6 wks | Thu 2/2/12 | Wed 3/14/12 |
| 16 | Award | 20 days | Wed 4/4/12 | Tue 5/1/12 |
| 17 | **New Gas Turbien or Diesel Engine Generator** | **247 days** | **Mon 5/14/12** | **Tue 4/23/13** |
| 18 | Award Gas Turbine (GT)/Engine Contract | 2 days | Mon 5/14/12 | Tue 5/15/12 |
| 19 | Manufacture & Deliver Transportable Engines | 45 wks | Wed 5/16/12 | Tue 3/26/13 |
| 20 | Install and Commission | 4 wks | Wed 3/27/13 | Tue 4/23/13 |
| 21 | **Fuel System** | **160 days** | **Wed 8/15/12** | **Tue 3/26/13** |
| 22 | Engineer | 12 wks | Wed 8/15/12 | Tue 11/6/12 |
| 23 | Order, Manufacture, Deliver | 12 wks | Wed 11/7/12 | Tue 1/29/13 |
| 24 | Install new fuel lines and receiving system | 6 wks | Wed 1/30/13 | Tue 3/12/13 |
| 25 | Commission System | 2 wks | Wed 3/13/13 | Tue 3/26/13 |
| 26 | **Electrical & Control Systmes** | **191 days** | **Tue 7/3/12** | **Tue 3/26/13** |
| 27 | Engineer | 12 wks | Tue 7/3/12 | Mon 9/24/12 |
| 28 | Order & Manufacture Elect & Control (E&C) Equip | 17 wks | Tue 11/6/12 | Mon 3/4/13 |
| 29 | Electrical Building Manufacture, Delivery, Install | 17 wks | Tue 9/25/12 | Mon 1/21/13 |
| 30 | Install New System | 7 days | Tue 3/5/13 | Wed 3/13/13 |
| 31 | RE-align Existing Plant Systems | 7 days | Thu 3/14/13 | Fri 3/22/13 |
| 32 | Commission unit | 2 days | Mon 3/25/13 | Tue 3/26/13 |
| 33 | **Site Civil Work** | **70 days** | **Wed 12/19/12** | **Tue 3/26/13** |
| 34 | Engineer | 12 wks | Wed 1/2/13 | Tue 3/26/13 |
| 35 | Generator area clearing and civil | 2 wks | Wed 3/13/13 | Tue 3/26/13 |
| 36 | Fuel line civil work | 6 wks | Wed 12/19/12 | Tue 1/29/13 |
| 37 | Electrical an contro cable civil work | 6 wks | Tue 1/22/13 | Mon 3/4/13 |
| 38 | Complete Unit Test | 10 days | Wed 4/24/13 | Tue 5/7/13 |
| 39 | Gas Turbine (GT) In-Service (I/S) | 0 days | Tue 5/7/13 | Tue 5/7/13 |
| 40 | **Decommission Existing GT** | **30 days** | **Wed 7/3/13** | **Tue 8/13/13** |
| 41 | Fuel delivery system | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 42 | Electrical & Controls | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 43 | GT | 4 wks | Wed 7/3/13 | Tue 7/30/13 |
| 44 | Building | 2 wks | Wed 7/31/13 | Tue 8/13/13 |



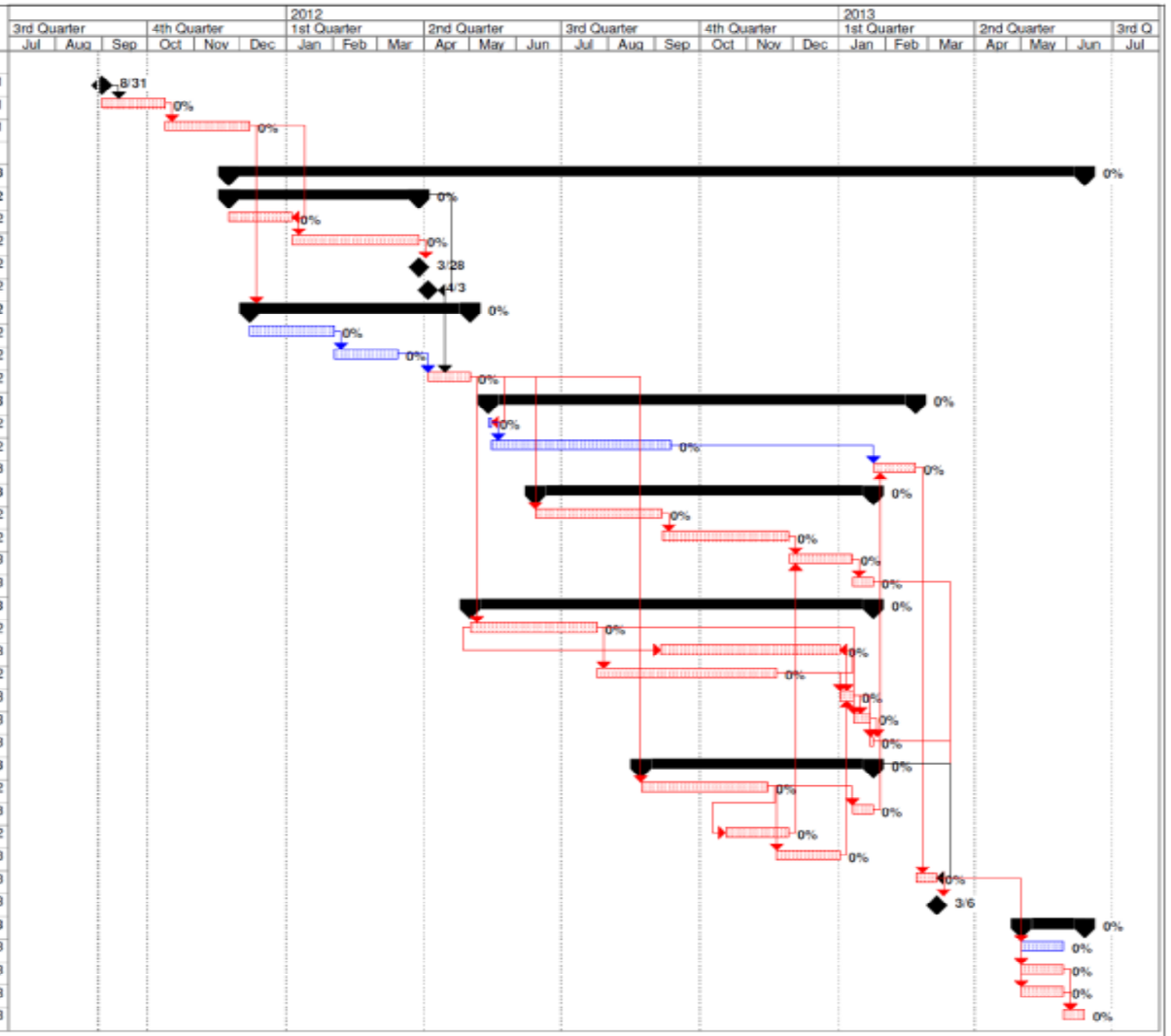

Project: Project1 New.mpp
Date: Mon 8/29/11

Critical
Critical Split
Critical Progress
Task
Split
Task Progress
Baseline
Baseline Split
Baseline Milestone
Milestone
Summary Progress
Summary
Project Summary
External Tasks
External Milestone
Deadline

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**FIGURE 3-7 SCHEDULE – NEW DIESEL GENSET**

| ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Condition Assessment Study | 0 wks | Wed 8/31/11 | Wed 8/31/11 |
| 3 | Hydro Internal Capital Budget Proposal Development | 6 wks | Thu 9/1/11 | Wed 10/12/11 |
| 4 | Submission - Public Utilities Board & Approval | 8 wks | Thu 10/13/11 | Wed 12/7/11 |
| 5 | | | | |
| 6 | **Nearly New gas Turbine (GT) or Diesel Generator Units** | **405 days** | **Thu 11/24/11** | **Wed 6/12/13** |
| 7 | **Project Environmental & Regulatory Approvals** | **90 days** | **Thu 11/24/11** | **Wed 3/28/12** |
| 8 | Prepare Dispersion Modelling & Submission | 30 days | Thu 11/24/11 | Wed 1/4/12 |
| 9 | Regulatory Review and Approval | 60 days | Thu 1/5/12 | Wed 3/28/12 |
| 10 | Environmental Approval | 0 days | Wed 3/28/12 | Wed 3/28/12 |
| 11 | Project Full Release | 0 days | Tue 4/3/12 | Tue 4/3/12 |
| 12 | **Request for Proposal (RFP) for Engineer Procure Construct (** | **104 days** | **Thu 12/8/11** | **Tue 5/1/12** |
| 13 | Prepare | 40 days | Thu 12/8/11 | Wed 2/1/12 |
| 14 | Bid | 6 wks | Thu 2/2/12 | Wed 3/14/12 |
| 15 | Award | 20 days | Wed 4/4/12 | Tue 5/1/12 |
| 16 | **Nearly New GT or Diesel Engine Generator** | **203 days** | **Mon 5/14/12** | **Wed 2/20/13** |
| 17 | Award GT/Diesel Engine Contract | 2 days | Mon 5/14/12 | Tue 5/15/12 |
| 18 | Manufacture & Deliver Transportable Engines | 17 wks | Wed 5/16/12 | Tue 9/11/12 |
| 19 | Install and Commission | 4 wks | Thu 1/24/13 | Wed 2/20/13 |
| 20 | **Fuel System** | **160 days** | **Thu 6/14/12** | **Wed 1/23/13** |
| 21 | Engineer | 12 wks | Thu 6/14/12 | Wed 9/5/12 |
| 22 | Order, Manufacture, Deliver | 12 wks | Thu 9/6/12 | Wed 11/28/12 |
| 23 | Install new fuel lines and receiving system | 6 wks | Thu 11/29/12 | Wed 1/9/13 |
| 24 | Commission System | 2 wks | Thu 1/10/13 | Wed 1/23/13 |
| 25 | **Electrical & Control Systmes** | **191 days** | **Wed 5/2/12** | **Wed 1/23/13** |
| 26 | Engineer | 12 wks | Wed 5/2/12 | Tue 7/24/12 |
| 27 | Order & Manufacture Elect & Control (E&C) Equip | 17 wks | Wed 9/5/12 | Tue 1/1/13 |
| 28 | Electrical Building Manufacture, Delivery, Install | 17 wks | Wed 7/25/12 | Tue 11/20/12 |
| 29 | Install New System | 7 days | Wed 1/2/13 | Thu 1/10/13 |
| 30 | RE-align Existing Plant Systems | 7 days | Fri 1/11/13 | Mon 1/21/13 |
| 31 | Commission unit | 2 days | Tue 1/22/13 | Wed 1/23/13 |
| 32 | **Site Civil Work** | **110 days** | **Thu 8/23/12** | **Wed 1/23/13** |
| 33 | Engineer | 12 wks | Thu 8/23/12 | Wed 11/14/12 |
| 34 | Generator area clearing and civil | 2 wks | Thu 1/10/13 | Wed 1/23/13 |
| 35 | Fuel line civil work | 6 wks | Thu 10/18/12 | Wed 11/28/12 |
| 36 | Electrical an contro cable civil work | 6 wks | Wed 11/21/12 | Tue 1/1/13 |
| 37 | Complete Unit Test | 10 days | Thu 2/21/13 | Wed 3/6/13 |
| 38 | GT In-Service (I/S) | 0 days | Wed 3/6/13 | Wed 3/6/13 |
| 39 | **Decommission Existing GT** | **30 days** | **Thu 5/2/13** | **Wed 6/12/13** |
| 40 | Fuel delivery system | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 41 | Electrical & Controls | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 42 | GT | 4 wks | Thu 5/2/13 | Wed 5/29/13 |
| 43 | Building | 2 wks | Thu 5/30/13 | Wed 6/12/13 |




Project: Project1 Nearly New.mpp
Date: Mon 8/29/11

Critical, Critical Split, Critical Progress, Task, Split, Task Progress, Baseline, Baseline Split, Baseline Milestone, Milestone, Summary Progress, Summary, Project Summary, External Tasks, External Milestone, Deadline

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**FIGURE 3-8 SCHEDULE – NEW DIESEL GENSET**

### 3.4.11 OMA Cost Estimate to 2020

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The operating costs shown are the same for both the new and nearly new cases. For the kind of operation required, peak and emergency operation (typically <=60 Hrs/Yr, the diesel packages normally would require only an annual service and inspection by qualified service personnel. Most utilities would exercise the equipment once a month to verify proper operation.

The costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit. The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on receiving the same value per MWh as the existing units would if they were to recover their fuelling costs plus marginal operating and maintenance costs. The fuelling and electricity prices are intended as representative and based on running the units 150 hours per year, whereas actual hours could be as half of this.. The actual values (average run capacity, sent out heat rate (SOHR) and hence fuel and electricity depend on how the testing is actually done.

**TABLE 3-19 NEW DIESEL GENSET – OMA COST ASSUMPTION**

**Assumptions**

| | | Fuelling |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 13,656 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,173 |
| Electricity Value (E) = Value for existing GT | $/MWh | $343 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| Operations | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

The resulting costs are:

**TABLE 3-20 NEW DIESEL GENSET – OMA COSTS**

New/Near New Diesel
1000's Cnd $ - 2011/Yr

| | Maintenance | Operations | Fuelling | Sub-Total | Electricity Value | Total |
|---|---|---|---|---|---|---|
| 2012 | $15 | $0 | $0 | $15 | $0 | $15 |
| 2013 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2014 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2015 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2016 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2017 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2018 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2019 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2020 | $0 | $40 | $155 | $195 | ($206) | ($11) |
| TOTAL | $155 | $323 | $1,237 | $1,714 | ($1,648) | $67 |

# 4 COMPARATIVE ANALYSIS OF OPTIONS

## 4.1 Economic Assumptions

### 4.1.1 Economic Parameters

The economic parameter values used for escalation rate (general, fuel, electricity rate), and discount rate (escalated and unescalated) are illustrated below, as well as the associated cumulative factors.

**TABLE 4-1 ECONOMIC FACTORS**

| | Escalation | | Discount Rate (Escalated $) | | Real Discount Rate (UnEscalated $) | | Fuel Escalation | | Electricity Value Escalation | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Escalation | Cumulative Escalation Factor | Discount Rate (Escalated $) | Discount Factor (Escalated $) | Discount Rate (UnEscalated $) | Discout Factor (Unescalated $) | Fuel Escalation Rate | Cumulative Fuel Escalation Factor | Electricity Value Escalation Rate | Cumulative Electricity Value Factor |
| | "A" | "B" = Previous B x (1+A) | "C" | "D" = Previous D x 1/(1+C) | "E" = "C"-"A" | "F" =Previous F x 1/(1+E) | "G" | "H" = Previous H x (1+G) | "I" | "J" = Previous J x (1+I) |
| **2011** | 0.00% | 1.000 | 10.00% | 1.000 | 7.50% | 1.000 | 0.00% | 1.000 | 0.00% | 1.000 |
| **2012** | 2.50% | 1.025 | 10.00% | 0.909 | 7.50% | 0.930 | 3.00% | 1.030 | 3.00% | 1.030 |
| **2013** | 2.50% | 1.051 | 10.00% | 0.826 | 7.50% | 0.865 | 3.00% | 1.061 | 3.00% | 1.061 |
| **2014** | 2.50% | 1.077 | 10.00% | 0.751 | 7.50% | 0.805 | 3.00% | 1.093 | 3.00% | 1.093 |
| **2015** | 2.50% | 1.104 | 10.00% | 0.683 | 7.50% | 0.749 | 3.00% | 1.126 | 3.00% | 1.126 |
| **2016** | 2.50% | 1.131 | 10.00% | 0.621 | 7.50% | 0.697 | 3.00% | 1.159 | 3.00% | 1.159 |
| **2017** | 2.50% | 1.160 | 10.00% | 0.564 | 7.50% | 0.648 | 3.00% | 1.194 | 3.00% | 1.194 |
| **2018** | 2.50% | 1.189 | 10.00% | 0.513 | 7.50% | 0.603 | 3.00% | 1.230 | 3.00% | 1.230 |
| **2019** | 2.50% | 1.218 | 10.00% | 0.467 | 7.50% | 0.561 | 3.00% | 1.267 | 3.00% | 1.267 |
| **2020** | 2.50% | 1.249 | 10.00% | 0.424 | 7.50% | 0.522 | 3.00% | 1.305 | 3.00% | 1.305 |

### 4.1.2 Economic Values - Failure to Operate

The analysis assumed a relative difference in the relative probability of failure to perform as required (with Option 1 – the New 2 x 5 MW GTG as the base against which the others are compared). This is based on the reasons provided previously.

**TABLE 4-2 ECONOMIC VALUES – FAILURE TO OPERATE ASSUMPTION**

| **Failure To Operate** | | % Probability once over 2013-2020 | Value of Hr Shutdown | # Hrs Per Shutdown | Probable $/Incident |
|---|---|---|---|---|---|
| | | % (A) | MM$/Hr (B) | Hrs (C) | MM$ (D) = AxBxC |
| Option 0 | Refurbished Unit | 10% | $5 | 20 | $10 |
| Option1 & 1A | New/Used 2 x 5 MW GT | 0% | $5 | 20 | $0 |
| Option 2 & 2A | New/Used 5x2 MW Diesel | 4% | $5 | 20 | $4 |

**Notes:**
Value/ Hr Shutdown = $5 MM (Impact to Newfoundland Economy)
Probability risk is relative to the new 2 x 5MW GT option
One occurrence assumed nominally in 2016
Probable $/incident increases proportional to (A), (B), or (C)

### 4.1.3 Economic Values –Terminal Values

Each of the options has a "terminal value" at the end of the 2020 period. The amount is a function of both the age and condition and market value of the units at that time, and/or of its internal value for redeployment for other uses within Hydro post 2020 (i.e. regional distribution line outage/maintenance support). Potential short term alternative uses prior to 2020 may also have value, but were not assessed. The terminal values assumed for the study are shown in Table 4-4.

**TABLE 4-3 OPTION TERMINAL VALUES IN 2020**

| Option | Purchased Equipment Cost M$ | System Terminal Value in 2020 M$ | Comment |
|---|---|---|---|
| Option 0 - Refurbished Existing Unit | $3.0 | $0 | Terminal value covers cost for demolition |
| Option 1 - New 2 x 5 MW GT | $10.9 | $7.0 | Low use, essentially new condition. |
| Option 1A - Nearly New 2 x 5 MW GT | $9.2 | $4.0 | Lower percent recovery than new given prior use. |
| Option 2 - New 5 x 2 MW Diesel Genset | $8.6 | $5.0 | Lower market value – more available. |
| Option 2A - Nearly New 5 x 2 MW Diesel Genset | $7.5 | $3.0 | Lower percent recovery than new given prior use. |

## 4.2 Capital Cost Comparison

Table 4-4 provides an overview of the total capital cost of the options.

**Option 0, Existing GTG Unit**

For Option 0, the existing GT Unit refurbishment, there are three relevant values.

- The base total ($4.462M) does not address the replacement of the unit's capacity during its extensive overhaul outage (12 to 22 weeks).
- The second case ("+ standby") is based on the assumption that a "replacement gas generator and power turbine" are leased and substituted for the current equipment during the overhaul outage. There is a strong likelihood that this is possible. It is assumed that other issues (gearbox oil leaks etc are fixed in relatively short time on site). It is unlikely that other major equipment such as a gearbox could be leased.
- The third option ("+ Rental Stby") assumes that two new 5 MW trailer mounted gas turbines are leased for the outage period and the necessary facilities to connect them installed. This is a very expensive option and auxiliary systems will have limited useful life. It is also likely to significantly extend the schedule. It is not seen as a viable option to pursuing Option 1 or 1A.

**Options 1 and 2, New and Nearly New, Used Gas Turbine Generator and Diesel Generator Units**

The difference in the New and Nearly New is mostly in the capital costs. It should be noted that there may be some additional costs required to retrofit nearly new units to meet the same or required standards as the new units that are designed to meet Holyrood requirements.

**TABLE 4-4 CAPITAL COST COMPARISON OF OPTIONS**

**Capital Cost Comparison**
**Capital cost estimate $1,000 Can 2011**

| Option Number | 0 | 1 | 1A | 2 | 2A |
|---|---|---|---|---|---|
| **Option** | **Existing GT Refurb** | **New 2 x 5 MW GT** | **Used 2 x 5 MW GT** | **New 5 x 2 MW Diesel** | **Used 5 x 2 MW Diesel** |
| GT/Diesel Cost | $2,950 | $10,865 | $9,234 | $8,553 | $7,453 |
| Civil Works | $224 | $131 | $131 | $131 | $131 |
| Electrical Works | $541 | $759 | $759 | $801 | $801 |
| BOP Systems | $330 | $129 | $129 | $129 | $129 |
| Existing Unit Demolition & Removal | $0 | $7 | $7 | $7 | $7 |
| **Sub-Total - Directs and Indirects** | $4,046 | $11,891 | $10,260 | $9,620 | $8,520 |
| Project Engineering | $324 | $625 | $544 | $513 | $458 |
| Project Management | $283 | $832 | $718 | $673 | $596 |
| Total | $4,652 | $13,348 | $11,522 | $10,807 | $9,575 |

| | |
|---|---|
| + Standby = Total | $4,825 |
| | |
| + New Rental Stdby = Total | $9,421 |

## 4.3 Operating Cost Comparison

Operating costs were assumed to include the ongoing maintenance costs (annual inspections, repairs, etc.), the operations costs (costs to run the unit on test), the fuelling costs (fuel costs to run the tests), and an electricity value credit.

**For Option 0, Existing GTG Unit**

The operating costs are shown for both a refurbished case and a non-refurbished case. The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

**TABLE 4-5 OMA ASSUMPTIONS – OPTION 0, EXISTING GTG**

**Assumptions**

| | | Fuelling |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 13,656 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,173 |
| Electricity Value (E) = AxB/1000 + $50 Mtce | $/MWh | $343 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| Operations | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

The non-refurbished case includes an assumption of an equipment failure with modest consequential damage in 2016.

**TABLE 4-6 OMA COSTS – OPTION 0, EXISTING GTG**

**Existing Unit**
**1000's Cnd $ - 2011/Yr**

| | Maintenance | | Operations | | Fuelling | | Sub-Total | | Electricity Value | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab | With Rehab | Without Rehab |
| 2012 | $15 | $15 | $0 | $0 | $0 | $0 | $15 | $15 | $0 | $0 | $15 | $15 |
| 2013 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2014 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2015 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2016 | $20 | $1,500 | $40 | $1 | $176 | $88 | $236 | $1,589 | ($206) | ($103) | $30 | $1,486 |
| 2017 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2018 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2019 | $20 | $15 | $40 | $0 | $176 | $0 | $236 | $15 | ($206) | $0 | $30 | $15 |
| 2020 | $0 | $0 | $40 | $0 | $176 | $0 | $216 | $0 | ($206) | $0 | $10 | $0 |
| TOTAL | $155 | $1,605 | $323 | $1 | $1,408 | $88 | $1,885 | $1,694 | ($1,648) | ($103) | $238 | $1,591 |

## For Option 1 and 1A – New and Nearly New 2 x 5MW GTG

The operating costs shown are the same for both the new and nearly new cases. The difference in the New and Nearly New is mostly in the capital costs. The vendor indicated that for the 6 month inspection the cost was to be 10,000 and for the yearly it was 18,000 and that these costs would be the same for both new and nearly new.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

**TABLE 4-7 OMA ASSUMPTIONS – OPTION 1, NEW TRANSPORTABLE GTG**

**Assumptions**

| | | |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 12,000 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,031 |
| Electricity Value (E) = Value for existing GT | $/MWh | $343.25 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

The resulting costs are:

**TABLE 4-8 OMA COSTS – OPTION 1, NEW TRANSPORTABLE GTG**

New/Near New GT
1000's Cnd $ - 2011/Yr

| | Maintenance | Operations | Fuelling | Sub-Total | Electricity Value | | Total |
|---|---|---|---|---|---|---|---|
| 2012 | $15 | $0 | $0 | $15 | $0 | | $15 |
| 2013 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2014 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2015 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2016 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2017 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2018 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2019 | $20 | $40 | $155 | $215 | ($206) | | $9 |
| 2020 | $0 | $40 | $155 | $195 | ($206) | | ($11) |
| TOTAL | $155 | $323 | $1,237 | $1,714 | ($1,648) | | $67 |

**For Option 2 and 2A – New and Nearly New 5 x 2MW Diesel Engine Generators**

The operating costs shown are the same for both the new and nearly new cases. The difference in the New and Nearly New is mostly in the capital costs.

The assumptions used for fuel, operations, and electricity value are illustrated below. The electricity value is premised on recovering fuelling costs plus marginal operating costs.

**TABLE 4-9 OMA ASSUMPTIONS – OPTION 2, NEW DIESEL GENSET**

**Assumptions**

| | | Fuelling |
|---|---|---|
| #2 Oil Fuel Price (A) | $/MMBTU | $21.47 |
| Unit Efficiency (B) | BTU/kWh | 13,656 |
| Average Running Capacity (C) | MW | 4 |
| Average Running Cost (D) = AxBxC/1000 | $/Hr | $1,173 |
| Electricity Value (E) = Value for existing GT | $/MWh | $343 |
| Electricity Value (F) = E*C | $/Hr OP | $1,373 |

| Operations | |
|---|---|
| 2 | Persons/Start (U) |
| 4 | Hrs/Start (V) |
| $70 | $/PersonHr (W) |
| $560 | $/Start (Z) = UxVxW |

The resulting costs are:

**TABLE 4-10 OMA COSTS – OPTION 2, NEW DIESEL GENSET**

New/Near New Diesel
1000's Cnd $ - 2011/Yr

| | Maintenance | Operations | Fuelling | Sub-Total | Electricity Value | Total |
|---|---|---|---|---|---|---|
| 2012 | $15 | $0 | $0 | $15 | $0 | $15 |
| 2013 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2014 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2015 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2016 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2017 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2018 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2019 | $20 | $40 | $155 | $215 | ($206) | $9 |
| 2020 | $0 | $40 | $155 | $195 | ($206) | ($11) |
| TOTAL | $155 | $323 | $1,237 | $1,714 | ($1,648) | $67 |

## 4.4 Life Cycle Cost Comparison

Table 4-11 presents a summary of the life cycle cost comparison of the options in 1) un-escalated non-discounted (not present worthed), 2) un-escalated discounted (present worthed), 3) escalated non-discounted (not present worthed), and 4) escalated discounted (present worthed) costs.

The existing unit refurbishment option costs include the lower cost standby option, assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $200,000 to the base cost.

The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly new GT leased option would add an additional $4.6 M.

The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million in 2016 for the existing GTG and $3 to 4 million for the 5 x 2 MW diesel options.

**TABLE 4-11 LIFE CYCLE COST COMPARISON SUMMARY**

| | | Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $14,825 | $1,885 | $1,408 | $18,118 | ($1,648) | $16,470 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $11,454 | $1,291 | $959 | $13,704 | ($1,122) | $12,582 |
| 3 | ESCALATED CASHFLOW | $16,260 | $2,159 | $1,660 | $20,079 | ($1,943) | $18,136 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $11,521 | $1,302 | $992 | $13,815 | ($1,161) | $12,654 |

| | | Option 1 New 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $6,348 | $1,714 | $1,237 | $9,300 | ($1,648) | $7,652 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $8,766 | $1,175 | $842 | $10,783 | ($1,122) | $9,661 |
| 3 | ESCALATED CASHFLOW | $4,940 | $1,963 | $1,459 | $8,362 | ($1,943) | $6,419 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $8,731 | $1,185 | $871 | $10,787 | ($1,161) | $9,626 |

| | Option 1A Used 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $7,522 | $1,714 | $1,237 | $10,473 | ($1,648) | $8,826 |
| 2 | $8,632 | $1,175 | $842 | $10,649 | ($1,122) | $9,527 |
| 3 | $6,815 | $1,963 | $1,459 | $10,236 | ($1,943) | $8,294 |
| 4 | $8,618 | $1,185 | $871 | $10,674 | ($1,161) | $9,513 |

| | | Option 2 New 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $9,807 | $323 | $1,237 | $11,366 | ($1,648) | $9,719 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $10,231 | $220 | $842 | $11,293 | ($1,122) | $10,171 |
| 3 | ESCALATED CASHFLOW | $9,358 | $370 | $1,459 | $11,187 | ($1,943) | $9,244 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $10,232 | $222 | $871 | $11,325 | ($1,161) | $10,164 |

| | Option 2A Used 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $10,575 | $323 | $1,237 | $12,134 | ($1,648) | $10,487 |
| 2 | $10,128 | $220 | $842 | $11,190 | ($1,122) | $10,068 |
| 3 | $10,593 | $370 | $1,459 | $12,422 | ($1,943) | $10,479 |
| 4 | $10,143 | $222 | $871 | $11,236 | ($1,161) | $10,075 |

The details of the un-escalated non-discounted (not present worthed) and unescalated discounted (present worthed) tables for the options, using the assumption in Section 4.1, are as follows:

**TABLE 4-12 LIFE CYCLE COST COMPARISON (UNESCALATED, NOT-DISCOUNTED AND DISCOUNTED)**

**UNESCALATED, NOT DISCOUNTED CASHFLOW**

| Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | | $0 | $0 | $0 | $0 | $0 |
| 2012 | $4,825 | $15 | $0 | $4,840 | $0 | $4,840 |
| 2013 | | $236 | $176 | $412 | ($206) | $206 |
| 2014 | | $236 | $176 | $412 | ($206) | $206 |
| 2015 | | $236 | $176 | $412 | ($206) | $206 |
| 2016 | $10,000 | $236 | $176 | $10,412 | ($206) | $10,206 |
| 2017 | | $236 | $176 | $412 | ($206) | $206 |
| 2018 | | $236 | $176 | $412 | ($206) | $206 |
| 2019 | | $236 | $176 | $412 | ($206) | $206 |
| 2020 | $0 | $216 | $176 | $392 | ($206) | $186 |
| Total | $14,825 | $1,885 | $1,408 | $18,118 | ($1,648) | $16,470 |

| Option 1 New 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | | $0 | $0 | $0 | $0 | $0 |
| 2012 | $13,348 | $15 | $0 | $13,363 | $0 | $13,363 |
| 2013 | | $215 | $155 | $370 | ($206) | $164 |
| 2014 | | $215 | $155 | $370 | ($206) | $164 |
| 2015 | | $215 | $155 | $370 | ($206) | $164 |
| 2016 | $0 | $215 | $155 | $370 | ($206) | $164 |
| 2017 | | $215 | $155 | $370 | ($206) | $164 |
| 2018 | | $215 | $155 | $370 | ($206) | $164 |
| 2019 | | $215 | $155 | $370 | ($206) | $164 |
| 2020 | ($7,000) | $195 | $155 | ($6,650) | ($206) | ($6,856) |
| Total | $6,348 | $1,714 | $1,237 | $9,300 | ($1,648) | $7,652 |

| Option 1A Used 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | | $0 | $0 | $0 | $0 | $0 |
| 2012 | $11,522 | $15 | $0 | $11,537 | $0 | $11,537 |
| 2013 | | $215 | $155 | $370 | ($206) | $164 |
| 2014 | | $215 | $155 | $370 | ($206) | $164 |
| 2015 | | $215 | $155 | $370 | ($206) | $164 |
| 2016 | $0 | $215 | $155 | $370 | ($206) | $164 |
| 2017 | | $215 | $155 | $370 | ($206) | $164 |
| 2018 | | $215 | $155 | $370 | ($206) | $164 |
| 2019 | | $215 | $155 | $370 | ($206) | $164 |
| 2020 | ($4,000) | $195 | $155 | ($3,650) | ($206) | ($3,856) |
| Total | $7,522 | $1,714 | $1,237 | $10,473 | ($1,648) | $8,826 |

| Option 2 New 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | | $0 | $0 | $0 | $0 | $0 |
| 2012 | $10,807 | $0 | $0 | $10,807 | $0 | $10,807 |
| 2013 | | $40 | $155 | $195 | ($206) | ($11) |
| 2014 | | $40 | $155 | $195 | ($206) | ($11) |
| 2015 | | $40 | $155 | $195 | ($206) | ($11) |
| 2016 | $4,000 | $40 | $155 | $4,195 | ($206) | $3,989 |
| 2017 | | $40 | $155 | $195 | ($206) | ($11) |
| 2018 | | $40 | $155 | $195 | ($206) | ($11) |
| 2019 | | $40 | $155 | $195 | ($206) | ($11) |
| 2020 | ($5,000) | $40 | $155 | ($4,805) | ($206) | ($5,011) |
| Total | $9,807 | $323 | $1,237 | $11,366 | ($1,648) | $9,719 |

| Option 2A used 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | | $0 | $0 | $0 | $0 | $0 |
| 2012 | $9,575 | $0 | $0 | $9,575 | $0 | $9,575 |
| 2013 | | $40 | $155 | $195 | ($206) | ($11) |
| 2014 | | $40 | $155 | $195 | ($206) | ($11) |
| 2015 | | $40 | $155 | $195 | ($206) | ($11) |
| 2016 | $4,000 | $40 | $155 | $4,195 | ($206) | $3,989 |
| 2017 | | $40 | $155 | $195 | ($206) | ($11) |
| 2018 | | $40 | $155 | $195 | ($206) | ($11) |
| 2019 | | $40 | $155 | $195 | ($206) | ($11) |
| 2020 | ($3,000) | $40 | $155 | ($2,805) | ($206) | ($3,011) |
| Total | $10,575 | $323 | $1,237 | $12,134 | ($1,648) | $10,487 |

**UNESCALATED, DISCOUTED CASHFLOW**

| Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $4,489 | $14 | $0 | $4,502 | $0 | $4,502 |
| 2013 | $0 | $204 | $152 | $357 | ($178) | $178 |
| 2014 | $0 | $190 | $142 | $332 | ($166) | $166 |
| 2015 | $0 | $177 | $132 | $309 | ($154) | $154 |
| 2016 | $6,966 | $165 | $123 | $7,253 | ($143) | $7,109 |
| 2017 | $0 | $153 | $114 | $267 | ($133) | $134 |
| 2018 | $0 | $142 | $106 | $248 | ($124) | $124 |
| 2019 | $0 | $132 | $99 | $231 | ($115) | $116 |
| 2020 | $0 | $113 | $92 | $205 | ($107) | $97 |
| Total | $11,454 | $1,291 | $959 | $13,704 | ($1,122) | $12,582 |

| Option 1 New 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $12,417 | $14 | $0 | $12,431 | $0 | $12,431 |
| 2013 | $0 | $186 | $134 | $320 | ($178) | $142 |
| 2014 | $0 | $173 | $124 | $297 | ($166) | $132 |
| 2015 | $0 | $161 | $116 | $277 | ($154) | $123 |
| 2016 | $0 | $150 | $108 | $257 | ($143) | $114 |
| 2017 | $0 | $139 | $100 | $239 | ($133) | $106 |
| 2018 | $0 | $130 | $93 | $223 | ($124) | $99 |
| 2019 | $0 | $121 | $87 | $207 | ($115) | $92 |
| 2020 | ($3,651) | $102 | $81 | ($3,469) | ($107) | ($3,576) |
| Total | $8,766 | $1,175 | $842 | $10,783 | ($1,122) | $9,661 |

| Option 1A Used 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $10,718 | $14 | $0 | $10,732 | $0 | $10,732 |
| 2013 | $0 | $186 | $134 | $320 | ($178) | $142 |
| 2014 | $0 | $173 | $124 | $297 | ($166) | $132 |
| 2015 | $0 | $161 | $116 | $277 | ($154) | $123 |
| 2016 | $0 | $150 | $108 | $257 | ($143) | $114 |
| 2017 | $0 | $139 | $100 | $239 | ($133) | $106 |
| 2018 | $0 | $130 | $93 | $223 | ($124) | $99 |
| 2019 | $0 | $121 | $87 | $207 | ($115) | $92 |
| 2020 | ($2,086) | $102 | $81 | ($1,904) | ($107) | ($2,011) |
| Total | $8,632 | $1,175 | $842 | $10,649 | ($1,122) | $9,527 |

| Option 2 New 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $10,053 | $0 | $0 | $10,053 | $0 | $10,053 |
| 2013 | $0 | $35 | $134 | $169 | ($178) | ($10) |
| 2014 | $0 | $32 | $124 | $157 | ($166) | ($9) |
| 2015 | $0 | $30 | $116 | $146 | ($154) | ($8) |
| 2016 | $2,786 | $28 | $108 | $2,922 | ($143) | $2,779 |
| 2017 | $0 | $26 | $100 | $126 | ($133) | ($7) |
| 2018 | $0 | $24 | $93 | $117 | ($124) | ($7) |
| 2019 | $0 | $23 | $87 | $109 | ($115) | ($6) |
| 2020 | ($2,608) | $21 | $81 | ($2,506) | ($107) | ($2,614) |
| Total | $10,231 | $220 | $842 | $11,293 | ($1,122) | $10,171 |

| Option 2A used 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $8,907 | $0 | $0 | $8,907 | $0 | $8,907 |
| 2013 | $0 | $35 | $134 | $169 | ($178) | ($10) |
| 2014 | $0 | $32 | $124 | $157 | ($166) | ($9) |
| 2015 | $0 | $30 | $116 | $146 | ($154) | ($8) |
| 2016 | $2,786 | $28 | $108 | $2,922 | ($143) | $2,779 |
| 2017 | $0 | $26 | $100 | $126 | ($133) | ($7) |
| 2018 | $0 | $24 | $93 | $117 | ($124) | ($7) |
| 2019 | $0 | $23 | $87 | $109 | ($115) | ($6) |
| 2020 | ($1,565) | $21 | $81 | ($1,463) | ($107) | ($1,570) |
| Total | $10,128 | $220 | $842 | $11,190 | ($1,122) | $10,068 |

Based on escalated cost assumptions in Section 4.1, the escalated non-discounted (not present worthed) and escalated discounted (present worthed) tables are as follows.

**TABLE 4-13 LIFE CYCLE COST COMPARISON (ESCALATED, NOT DISCOUNTED AND DISCOUNTED, PRESENT VALUED)**

**ESCALATED, NOT DISCOUNTED CASHFLOW**

| Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $4,946 | $15 | $0 | $4,961 | $0 | $4,961 |
| 2013 | $0 | $248 | $187 | $435 | ($218) | $216 |
| 2014 | $0 | $254 | $192 | $447 | ($225) | $222 |
| 2015 | $0 | $261 | $198 | $459 | ($232) | $227 |
| 2016 | $11,314 | $267 | $204 | $11,785 | ($239) | $11,547 |
| 2017 | $0 | $274 | $210 | $484 | ($246) | $238 |
| 2018 | $0 | $281 | $216 | $497 | ($253) | $244 |
| 2019 | $0 | $288 | $223 | $511 | ($261) | $250 |
| 2020 | $0 | $270 | $230 | $500 | ($269) | $231 |
| Total | $16,260 | $2,159 | $1,660 | $20,079 | ($1,943) | $18,136 |

| Option 1 New 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $13,682 | $15 | $0 | $13,697 | $0 | $13,697 |
| 2013 | $0 | $226 | $164 | $390 | ($218) | $171 |
| 2014 | $0 | $231 | $169 | $400 | ($225) | $175 |
| 2015 | $0 | $237 | $174 | $411 | ($232) | $179 |
| 2016 | $0 | $243 | $179 | $422 | ($239) | $184 |
| 2017 | $0 | $249 | $185 | $434 | ($246) | $188 |
| 2018 | $0 | $255 | $190 | $446 | ($253) | $192 |
| 2019 | $0 | $262 | $196 | $458 | ($261) | $197 |
| 2020 | ($8,742) | $243 | $202 | ($8,297) | ($269) | ($8,566) |
| Total | $4,940 | $1,963 | $1,459 | $8,362 | ($1,943) | $6,419 |

| Option 1A Used 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $11,810 | $15 | $0 | $11,826 | $0 | $11,826 |
| 2013 | $0 | $226 | $164 | $390 | ($218) | $171 |
| 2014 | $0 | $231 | $169 | $400 | ($225) | $175 |
| 2015 | $0 | $237 | $174 | $411 | ($232) | $179 |
| 2016 | $0 | $243 | $179 | $422 | ($239) | $184 |
| 2017 | $0 | $249 | $185 | $434 | ($246) | $188 |
| 2018 | $0 | $255 | $190 | $446 | ($253) | $192 |
| 2019 | $0 | $262 | $196 | $458 | ($261) | $197 |
| 2020 | ($4,995) | $243 | $202 | ($4,550) | ($269) | ($4,819) |
| Total | $6,815 | $1,963 | $1,459 | $10,236 | ($1,943) | $8,294 |

| Option 2 New 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $11,077 | $0 | $0 | $11,077 | $0 | $11,077 |
| 2013 | $0 | $42 | $164 | $206 | ($218) | ($12) |
| 2014 | $0 | $43 | $169 | $212 | ($225) | ($13) |
| 2015 | $0 | $45 | $174 | $219 | ($232) | ($13) |
| 2016 | $4,526 | $46 | $179 | $4,750 | ($239) | $4,512 |
| 2017 | $0 | $47 | $185 | $231 | ($246) | ($15) |
| 2018 | $0 | $48 | $190 | $238 | ($253) | ($15) |
| 2019 | $0 | $49 | $196 | $245 | ($261) | ($16) |
| 2020 | ($6,244) | $50 | $202 | ($5,992) | ($269) | ($6,261) |
| Total | $9,358 | $370 | $1,459 | $11,187 | ($1,943) | $9,244 |

| Option 2A used 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $9,814 | $0 | $0 | $9,814 | $0 | $9,814 |
| 2013 | $0 | $42 | $164 | $206 | ($218) | ($12) |
| 2014 | $0 | $43 | $169 | $212 | ($225) | ($13) |
| 2015 | $0 | $45 | $174 | $219 | ($232) | ($13) |
| 2016 | $4,526 | $46 | $179 | $4,750 | ($239) | $4,512 |
| 2017 | $0 | $47 | $185 | $231 | ($246) | ($15) |
| 2018 | $0 | $48 | $190 | $238 | ($253) | ($15) |
| 2019 | $0 | $49 | $196 | $245 | ($261) | ($16) |
| 2020 | ($3,747) | $50 | $202 | ($3,494) | ($269) | ($3,763) |
| Total | $10,593 | $370 | $1,459 | $12,422 | ($1,943) | $10,479 |

**ESCALATED, DISCOUTED CASHFLOW**

| Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $4,496 | $14 | $0 | $4,510 | $0 | $4,510 |
| 2013 | $0 | $205 | $154 | $359 | ($181) | $179 |
| 2014 | $0 | $191 | $144 | $336 | ($169) | $167 |
| 2015 | $0 | $178 | $135 | $313 | ($158) | $155 |
| 2016 | $7,025 | $166 | $127 | $7,318 | ($148) | $7,170 |
| 2017 | $0 | $155 | $119 | $273 | ($139) | $134 |
| 2018 | $0 | $144 | $111 | $255 | ($130) | $125 |
| 2019 | $0 | $134 | $104 | $238 | ($122) | $117 |
| 2020 | $0 | $115 | $97 | $212 | ($114) | $98 |
| Total | $11,521 | $1,302 | $992 | $13,815 | ($1,161) | $12,654 |

| Option 1 New 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $12,438 | $14 | $0 | $12,452 | $0 | $12,452 |
| 2013 | $0 | $187 | $136 | $322 | ($181) | $142 |
| 2014 | $0 | $174 | $127 | $301 | ($169) | $132 |
| 2015 | $0 | $162 | $119 | $281 | ($158) | $123 |
| 2016 | $0 | $151 | $111 | $262 | ($148) | $114 |
| 2017 | $0 | $141 | $104 | $245 | ($139) | $106 |
| 2018 | $0 | $131 | $98 | $229 | ($130) | $99 |
| 2019 | $0 | $122 | $91 | $214 | ($122) | $92 |
| 2020 | ($3,707) | $103 | $86 | ($3,519) | ($114) | ($3,633) |
| Total | $8,731 | $1,185 | $871 | $10,787 | ($1,161) | $9,626 |

| Option 1A Used 2x5 MW GT | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $10,737 | $14 | $0 | $10,750 | $0 | $10,750 |
| 2013 | $0 | $187 | $136 | $322 | ($181) | $142 |
| 2014 | $0 | $174 | $127 | $301 | ($169) | $132 |
| 2015 | $0 | $162 | $119 | $281 | ($158) | $123 |
| 2016 | $0 | $151 | $111 | $262 | ($148) | $114 |
| 2017 | $0 | $141 | $104 | $245 | ($139) | $106 |
| 2018 | $0 | $131 | $98 | $229 | ($130) | $99 |
| 2019 | $0 | $122 | $91 | $214 | ($122) | $92 |
| 2020 | ($2,119) | $103 | $86 | ($1,930) | ($114) | ($2,044) |
| Total | $8,618 | $1,185 | $871 | $10,674 | ($1,161) | $9,513 |

| Option 2 New 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $10,070 | $0 | $0 | $10,070 | $0 | $10,070 |
| 2013 | $0 | $35 | $136 | $171 | ($181) | ($10) |
| 2014 | $0 | $33 | $127 | $160 | ($169) | ($10) |
| 2015 | $0 | $30 | $119 | $149 | ($158) | ($9) |
| 2016 | $2,810 | $28 | $111 | $2,950 | ($148) | $2,801 |
| 2017 | $0 | $26 | $104 | $131 | ($139) | ($8) |
| 2018 | $0 | $25 | $98 | $122 | ($130) | ($8) |
| 2019 | $0 | $23 | $91 | $114 | ($122) | ($7) |
| 2020 | ($2,648) | $21 | $86 | ($2,541) | ($114) | ($2,655) |
| Total | $10,232 | $222 | $871 | $11,325 | ($1,161) | $10,164 |

| Option 2A used 5 x 2 MW Diesel | | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 2011 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2012 | $8,922 | $0 | $0 | $8,922 | $0 | $8,922 |
| 2013 | $0 | $35 | $136 | $171 | ($181) | ($10) |
| 2014 | $0 | $33 | $127 | $160 | ($169) | ($10) |
| 2015 | $0 | $30 | $119 | $149 | ($158) | ($9) |
| 2016 | $2,810 | $28 | $111 | $2,950 | ($148) | $2,801 |
| 2017 | $0 | $26 | $104 | $131 | ($139) | ($8) |
| 2018 | $0 | $25 | $98 | $122 | ($130) | ($8) |
| 2019 | $0 | $23 | $91 | $114 | ($122) | ($7) |
| 2020 | ($1,589) | $21 | $86 | ($1,482) | ($114) | ($1,596) |
| Total | $10,143 | $222 | $871 | $11,236 | ($1,161) | $10,075 |

# 5 CONCLUSIONS

## 5.1 Existing Gas Turbine Generator Unit

1. The existing GT generator should not be operated (started, operated, shutdown) except in an emergency situation, and in such an emergency its operation should be observe remotely to ensure personnel safety.
    i) Fire from lube oil system gearbox seals remains a possible safety issue.
    ii) Catastrophic failure of the power turbine disk is a possibility due to corrosion and high stress that may be present at blade roots and attachments
2. The existing GT generator requires extensive overhaul and repair work:
    x) Power turbine disk may require replacement (9 month manufacturing lead time)
    xi) One or more power turbine blades may require replacement or significant repair
    xii) Gas generator blading requires cleaning and recoating
    xiii) Inlet filter media requires replacement and inlet duct requires refurbishment (including cooling air duct to power turbine disk)
    xiv) Exhaust stack requires replacement or extensive repairs
    xv) Gearbox lube oil system requires modification and refurbishment
        e. Seals require replacement/modification
        f. Venting system modifications required to reduce lube oil pressure buildup
        g. Lube oil pump system requires upgrade for start-ups.
        h. Lube oil cooling fan is experiencing some leaks and snow and ice and water build-ups in its containment can cause start-issues
    xvi) Gearbox bearings likely worn and need refurbishment or replacement and/or unit re-alignment
    xvii) Unit generator requires significant testing and possibly rewind
    xviii) Unit generator exciter needs refurbishment and likely replacement
3. GT electrical and controls system has elements that are not in compliance with current standards and/or are obsolete and hence necessitates replacement:
    iii) Unit AVR
    iv) Unit MCC's
4. The GT and generator enclosure rooms require modification to their fire detection and suppression systems to provide better coverage, as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010.
5. GT fuel oil receiving, forwarding, and delivery system are in operable condition, but climatic conditions (icing, snow-buildup, water build-ups from rain, rusting from salty ambient air) result in significant periods where starts may fail or be significantly delayed. The GT generator building is in generally good condition, except for:
    iv) Major leaks in and around the GT exhaust stack which are impacting the gas turbine power turbine volute and back end blades;
    v) Minor leaks at generator ventilation stack; and
    vi) Minor air leaks as a result of minor siding holes (corrosion) which require repair/ refurbishment
6. The electrical services room require expansion to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash).

7. The earliest in-service dates for refurbishing the existing unit and returning it to service:
    a. Without back-up during the existing unit outage, but restricting the outage to lower risk, late spring to early fall periods is October 2013, with a roughly six month outage.
    b. With a nearly new 2 x 5 MW GT leased unit required during an existing unit outage is July 2013 with the existing unit on outage about five months.
    c. With shorter duration engineering and procurement times for BOP, fuel system and electrical systems, the in-service can theoretically be advance two to three months, but outage scheduling would likely mitigate this.

    Note: Using leased parts during outage, or procuring used parts and refurbishing them, has no significant positive impact.
8. The capital cost for refurbishing the existing unit is between $4.5 and $5 million, depending on the amount of additional work found during refurbishment. If leasing a replacement 2 x 5 MW unit is required to avoid any outage, then the total capital cost would be between $9.5 and $10.0 million, depending on the market price and availability of portable/mobile equipment. There is some opportunity to slightly reduce costs if used parts for the unit, and in particular the power turbine disk, are available.

## 5.2 New and Nearly-New 2 x 5 MW Portable/Transportable Gas Turbine Generator Units

1. The two 5 MW transportable gas turbine units option is consistent with the requirements for black start power, the need to start a 3 MW power block (one boiler feed pump motor), and simplicity of managing the number of black start units in parallel.
2. The space requirements for the two 5 MW transportable gas turbine units (2 trailers each plus a common electrical building) cannot be accommodated in the existing GT area.
3. Space and civil requirements support the use of the existing well graded area behind the old security building as the best location.
4. Two new 5 MW transportable gas turbine units could be readily purchased, with a manufacturing time of about 12 months.
5. Two nearly new, used 5 MW transportable GT units may be possible to acquire to a shorter time. Their availability and cost are functions of the market place. The units may also have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).
6. Emissions, particularly NOx emissions, will have to be addressed:
    iv) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.
    v) NOx emissions will be lower than those of the current GTG units, but being oil fuelled units will be challenged to meet Canadian Council of Ministers of the Environment (CCME gas turbine NOx emission guidelines
    vi) Newfoundland & Labrador environmental regulations require Best Available Control Technology (BACT), although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.
        c. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.

d. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on the unit such as a limit on the number of operating hours per year.

7. Five MW units are likely the upper limit of useful unit size for redeployment in support of transmission and distribution line maintenance support either post 2020 or periods up to 2020.

8. The earliest in-service date for procuring and installing 2 x 5 MW new gas turbine generators is May 2013. The earliest in-service date for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is March 2013.

9. The capital cost for procuring and installing 2 x 5 MW new gas turbine generators is $13.3 million. The capital cost for procuring and installing 2 x 5 MW nearly new/used gas turbine generators is $11.5 million.

## 5.3 New and Nearly-New 5 x 2 MW Portable/Transportable Diesel Engine Generator Units

1. The five 2 MW transportable diesel engine generator units option is potentially consistent with the requirements for black start power, but:

   i) The units may have significant difficulty responding to a block load start of 3 MW power block (one boiler feed pump motor), and

   ii) Islanded synchronous operation during start-up of five units may be difficult to maintain and affect overall system capacity available and overall system start-up reliability. It will also likely require a more complex control system.

2. The space requirements for the five 2 MW transportable diesel engine generator units (5 trailers plus two electrical trailers plus a common electrical building) cannot be accommodated in the existing GT area.

   i) Space and civil requirements suggested that use of the existing well graded area behind the old security building was the best location.

   ii) Spacing requirements are increased by separation requirements between units

3. Five new 2 MW transportable diesel engine generator units could be readily purchased, with a manufacturing time of about 12 months.

4. Five nearly new, used 2 MW transportable diesel engine generator units may be possible to acquire to a shorter time. Their availability and cost are functions of the marketplace and the units may have to be adapted to suit Holyrood conditions (motor and start voltages, applicable codes, design fuel combustors, NOx levels).

5. Emissions, particularly NOx emissions, will have to be addressed:

   i) NOx emissions are dependent on the nitrogen content of the diesel fuel oil used.

   ii) NOx emissions, particularly for some used engines, may not be lower than those of the existing GT unit. They will have higher emission levels than the GT options.

   iii) Applicable diesel engine generator emission regulations in the US and Canada are in flux, with significantly more stringent requirements likely for units coming into service in the 2012 through 2015 period. Emergency power non-mobile (i.e. not on road or off-road units) will face significant but less stringent levels, but will have their operation limited to emergency use only (in effect similar to the restriction imposed on the existing GT).

   iv) Newfoundland & Labrador environmental regulations require BACT, although the regulations have provisions relaxing BACT requirements for both economic impacts as well as flexibility of approval by the Minister considering roles.

a. The current designs do not have special technology (i.e. Selective Catalytic Reduction (SCR)). Their costs, the impacts of the technology on black start readiness and reliability, and the costs and impacts of ammonia use and storage for SCR use, make their consideration unreasonable for the roles contemplated.
b. A project going forth will have to seek approval for an exemption from the BACT requirement, and will likely have restrictions placed on its role and likely a limit on the number of operating hours per year.

6. Two MW units are good candidates for redeployment in support of transmission and distribution line maintenance support either post 2020 or in possible periods up to 2020. They are typical of larger unit sizes deployed for that purpose now.
7. The earliest in-service date for procuring and installing 5 x 2 MW new diesel gensets is May 2013. The earliest in-service date for procuring and installing 5 x 2 MW nearly new/used diesel gensets is March 2013.
8. The capital cost for procuring and installing 5 x 2 MW new diesel gensets is $10.8 million. The capital cost for procuring and installing 5 x 2 MW nearly new/used diesel gensets is $9.6 million.

## 5.4 Overall Economics

Using the Assessment Basis,

1. The base capital cost comparison of the options is as follows:

**BASE CAPITAL COST COMPARISON OF OPTIONS**

**Capital Cost Comparison**
Capital cost estimate $1,000 Can 2011

| Option Number | 0 | 1 | 1A | 2 | 2A |
|---|---|---|---|---|---|
| Option | Existing GT Refurb | New 2 x 5 MW GT | Used 2 x 5 MW GT | New 5 x 2 MW Diesel | Used 5 x 2 MW Diesel |
| GT/Diesel Cost | $2,950 | $10,885 | $9,234 | $8,553 | $7,453 |
| Civil Works | $224 | $131 | $131 | $131 | $131 |
| Electrical Works | $541 | $759 | $759 | $801 | $801 |
| BOP Systems | $330 | $129 | $129 | $129 | $129 |
| Existing Unit Demolition & Removal | $0 | $7 | $7 | $7 | $7 |
| **Sub-Total - Directs and Indirects** | $4,048 | $11,891 | $10,260 | $9,620 | $8,520 |
| Project Engineering | $324 | $625 | $544 | $513 | $458 |
| Project Management | $283 | $832 | $718 | $673 | $596 |
| Total | $4,652 | $13,348 | $11,522 | $10,807 | $9,575 |

| | |
|---|---|
| + Standby = Total | $4,825 |
| | |
| + New Rental Stdby = Total | $9,421 |

2. The life cycle cost comparison of the options in:

- un-escalated non-discounted (not present worthed),
- un-escalated discounted (present worthed),
- escalated non-discounted (not present worthed), and
- escalated discounted (present worthed) costs is as follows.

The existing unit refurbishment option costs include the lower cost standby option assuming that a replacement gas generator and power turbine are leased and installed while the existing units are sent out for refurbishment. This adds only about $170,000 to the base cost. The existing unit refurbishment option costs assuming the standby option using a complete, installed 2 x 5 MW nearly new GT leased option would add an additional $4.7 M. The options include a cost for differences in the likelihood of a failure occurring once during the period – an additional $10 million in 2016 for the existing GT and $3 to 4 million in 2016 for the 5 x 2 MW diesel options.

| | | Refurbished Unit, Use of Spare Gas Generator & Power Turbine | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $14,825 | $1,885 | $1,408 | $18,118 | ($1,648) | $16,470 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $11,454 | $1,291 | $959 | $13,704 | ($1,122) | $12,582 |
| 3 | ESCALATED CASHFLOW | $16,260 | $2,159 | $1,660 | $20,079 | ($1,943) | $18,136 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $11,521 | $1,302 | $992 | $13,815 | ($1,161) | $12,654 |

| | | Option 1 New 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $6,348 | $1,714 | $1,237 | $9,300 | ($1,648) | $7,652 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $8,766 | $1,175 | $842 | $10,783 | ($1,122) | $9,661 |
| 3 | ESCALATED CASHFLOW | $4,940 | $1,963 | $1,459 | $8,362 | ($1,943) | $6,419 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $8,731 | $1,185 | $871 | $10,787 | ($1,161) | $9,626 |

| | Option 1A Used 2x5 MW GT | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $7,522 | $1,714 | $1,237 | $10,473 | ($1,648) | $8,826 |
| 2 | $8,632 | $1,175 | $842 | $10,649 | ($1,122) | $9,527 |
| 3 | $6,815 | $1,963 | $1,459 | $10,236 | ($1,943) | $8,294 |
| 4 | $8,618 | $1,185 | $871 | $10,674 | ($1,161) | $9,513 |

| | | Option 2 New 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|---|
| | | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | UNESCALATED | $9,807 | $323 | $1,237 | $11,366 | ($1,648) | $9,719 |
| 2 | UNESCALATED, DISCOUTED CASHFLOW | $10,231 | $220 | $842 | $11,293 | ($1,122) | $10,171 |
| 3 | ESCALATED CASHFLOW | $9,358 | $370 | $1,459 | $11,187 | ($1,943) | $9,244 |
| 4 | ESCALATED, DISCOUTED CASHFLOW | $10,232 | $222 | $871 | $11,325 | ($1,161) | $10,164 |

| | Option 2A Used 5x2MW Diesel | | | | | |
|---|---|---|---|---|---|---|
| | Capital Cost | OMA | Fuel | Sub-Total | Elect Value | Total |
| 1 | $10,575 | $323 | $1,237 | $12,134 | ($1,648) | $10,487 |
| 2 | $10,128 | $220 | $842 | $11,190 | ($1,122) | $10,068 |
| 3 | $10,593 | $370 | $1,459 | $12,422 | ($1,943) | $10,479 |
| 4 | $10,143 | $222 | $871 | $11,236 | ($1,161) | $10,075 |

# 6 RECOMMENDATIONS

1. The existing gas turbine generator should not be operated (started, operated, shut down), except in an emergency situation, and in such an emergency its operation should be observed remotely.
2. Using the Assessment Basis, the preferred option is Option 1, the 2 x 5 MW new GT installation.
3. Hydro should review the Assessment Basis and any impacts of changes in it as part of its internal decision-making process on the options.
4. Hydro should proceed with a preferred option as soon as practically possible, given that the likelihood of safely and successfully starting the existing GT unit in an emergency condition in its existing state is very poor and likely to decrease rapidly with time idle.
5. If Hydro internally chooses refurbishment of the existing GT generator as its preferred option, then the existing GT generator should undergo an extensive overhaul and repair program, including:

    i) Gas Turbine Unit

        a. Power turbine disk replacement (9 month manufacturing lead time);
        b. Power turbine damaged blades replacement (one or more) or significant repair;
        c. Gas generator blading cleaning and recoating;
        d. Inlet filter media replacement and inlet duct refurbishment (including cooling air duct to power turbine disk); and
        e. Exhaust stack replacement or extensive repairs

    ii) Gearbox lube oil system modification and refurbishment

        a. Seals replacement/modification;
        b. Venting system modifications to reduce lube oil pressure buildup;
        c. Lube oil pump system upgrade for start-ups; and
        d. Lube oil cooling fan replacement

    iii) Gearbox bearings refurbishment or replacement and/or unit re-alignment

    iv) GT Generator testing and refurbishment

        a. Unit generator electrical testing and possible rewind; and
        b. Unit generator exciter testing, and refurbishment/replacement as necessary

    v) GT electrical and controls system update to compliance with current standards and/or obsolescence replacement

        a. Unit AVR
        b. Unit MCC's

    vi) The GT and generator enclosure rooms' fire detection and suppression systems modifications to provide better coverage (as evidenced by the failure of the system to initially detect or suppress the gearbox lube oil fire in 2010).

    vii) GT fuel oil receiving, forwarding, and delivery system replacement in an enclosed shed.

    viii) GT generator building repairs:

        a. Major leaks in and around the gas turbine exhaust stack
        b. Minor leaks at generator ventilation stack
        c. Minor air leaks as a result of minor siding holes (corrosion)

    ix) Expansion of the electrical services room to allow for new electrical systems and current systems to be in compliance with current standards (i.e. space, separation distance for arc flash)

# APPENDIX 1
# GENERAL ARRANGEMENT DRAWING

# APPENDIX 2
# SEQUENCE OF EVENTS REPORT

# APPENDIX 3
# COST REPORT BY WORK ORDER/ASSET

# APPENDIX 4
# BUDGETARY INFORMATION - SOLAR TURBINES

# APPENDIX 5
# BUDGETARY INFORMATION - PETERSON POWER SYSTEMS

# APPENDIX 6
## BUDGETARY INFORMATION - ROLLS ROYCE

# APPENDIX 7
# EXISTING UNIT REFURBISHMENT CAPITAL COST DETAILS

# Appendix 7

## EXISTING UNIT REFURBISHMENT CAPITAL COST DETAILS

### Base Existing GT Unit Refurbishment

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| Gas Turbine Generator & Auxiliaries | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | **Gas Generator (Avon)** | **$500** | **$0** | **$500** | **$400-$700** |
| | **Power Turbine** | **$534** | **$402** | **$936** | **$900-$1,100** |
| | Disassemble/reassemble | $0 | $75 | $75 | |
| | New Disk | $331 | $0 | $331 | |
| | Moving blades | $93 | $0 | $93 | |
| | Rotor rehabilitation | $0 | $282 | $282 | |
| | Inlet structure repairs | $10 | $5 | $15 | |
| | Diaphragm section | $30 | $10 | $40 | |
| | Bearings | $50 | $20 | $70 | |
| | Exhaust volute | $20 | $10 | $30 | |
| | **Gearbox** | **$125** | **$39** | **$164** | **$125-$200** |
| | Bearings | $80 | $34 | $114 | |
| | Gearbox venting | $20 | $5 | $25 | |
| | Contingency; 2nd opinion | $25 | $0 | $25 | |
| | **Generator and aux** | **$950** | **$0** | **$950** | **$150-$1,200** |
| | Generator | $900 | $0 | $900 | |
| | Exciter | $50 | $0 | $50 | |
| | **Inlet filter** | **$120** | **$30** | **$150** | **$100-$1200** |
| | **Exhaust stack** | **$40** | **$10** | **$50** | **$30-$75** |
| | **Commission unit** | | **$50** | **$50** | **$30-$75** |
| | **Sub-Total** | **$2,269** | **$531** | **$2,800** | **$2,400-$3,500** |
| | **Contingency (excl Avon)** | **$125** | **$25** | **$150** | **$100-$250** |
| | **SUB-TOTAL -GTG & Auxiliaries** | **$2,394** | **$556** | **$2,950** | **$2,500 - $3,750** |

| Site Civil & Structural Works - Rental Unit | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Geotech Investigation - bearing capacity of soil | $0 | $4 | $4 | $3-$10 |
| | Pre-engineered shelter for elec. equipment | $40 | $5 | $45 | $37-$55 |
| | Concrete cable trench | $60 | $10 | $70 | $60-$85 |
| | Repair sections of roofing and siding that are corroded | $3 | $2 | $5 | $3-$8 |
| | Building extension shelter - for elec. equipment expansion | $30 | $10 | $40 | $30-$50 |
| | Building extension shelter - turbine fuel line mechanical equipment | $30 | $10 | $40 | $30-$50 |
| | **Sub-Total** | **$163** | **$41** | **$204** | **$175-$250** |
| 10% | **Contingency** | **$16** | **$4** | **$20** | **$20-$25** |
| | **TOTAL Civil Works** | **$179** | **$45** | **$224** | **$195-$275** |

## Base Existing GT Unit Refurbishment (Contd)

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| Electrical Systems | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Installation new 800A, 13.8 kV, 3ph, 60Hz Generator Main Breaker | $126.86 | $12.80 | $139.66 | |
| | Removal of Existing Main Breaker | | $1.60 | $1.60 | |
| | Installation of Cable Tray | $3.50 | $1.25 | $4.75 | |
| | Installation of New Junction Box | $1.00 | $0.48 | $1.48 | |
| | Removal of Existing Power Cables from Existing Breaker to Generator and T9 Transformer | | $1.60 | $1.60 | |
| | Installation of New Power Cables from New Breaker to Generator (2 x 500kcmil) and T9 Transformer (2x500kcmil) | $50.00 | $10.00 | $60.00 | |
| | Connection of Existing and Used CT, PT and Control Cables in New JB, and run the new CT, PT and Control Cables from new JB to new 13.8 kV Main Breaker (4 x 4c10, 1 x 4c12, 1 x 12c12). | $0.60 | $1.60 | $2.20 | |
| | Installation of New 13.8kV Fusible Switch | | | $0.00 | |
| | Removal of Existing 13.8 kV Fusible Switch | | $1.60 | $1.60 | |
| | Install 3c2AWG, Teeck, 15kV, Cable from 112kVA Transformer to new 13.8kV Fusible Switch | $0.75 | $0.30 | $1.05 | |
| | Remove Existing MCC | | $8.00 | $8.00 | |
| | Install New MCC | $30.00 | $8.00 | $38.00 | |
| | Install Cable Tray | $1.60 | $0.90 | $2.50 | |
| | Install New Incoming and Feeder Cables for 600V Circuits | | | $0.00 | |
| | 3C12, Teck, 1000V, (Seven Circuits) | $1.26 | $0.53 | $1.79 | |
| | 3c10, Teck, 1000V, (One Circuit) | $0.24 | $0.12 | $0.36 | |
| | 3c6, Teck, 1000V, (Five Circuits) | $1.03 | $0.35 | $1.38 | |
| | 3c2, Teck, 1000V, (One Circuit) | $1.04 | $0.20 | $1.24 | |
| | Install New 230V, 3ph, Auxiliary Distribution Panel | $0.65 | $0.35 | $1.00 | |
| | Relocate 30kVA, 3ph, 550:230V Transformer and Connect to MCC and New 230V, 3ph, Auxiliary Distribution Panel | | $3.00 | $3.00 | |
| | 3c12, Teck, 1000V (One Circuit) | $0.18 | $0.08 | $0.26 | |
| | 3c10, Teck, 1000V, (Two Circuits) | $0.12 | $0.06 | $0.18 | |
| | Install new 110VDC,. NEMA 1 Breaker, new NEMA1 Splitter, new DC Starters, and Existing 100A DC Distribution Panel | $31.00 | $6.40 | $37.40 | |
| | **Install New Feeders from Splitter to DC Starters and DC Distribution Panel** | | | $0.00 | |
| | 3c12, Teck, 1000V (One Circuit) | $0.18 | $0.08 | $0.26 | |
| | 3c10, Teck, 1000V, (One Circuit) | $0.21 | $0.12 | $0.33 | |
| | 3c2, Teck 1000V (One Circuit) | $0.41 | $0.14 | $0.55 | |
| | Remove Existing AVR/Start Rectifier | | $1.60 | $1.60 | |
| | Install New AVR/Start Rectifier | $145.00 | $20.00 | $165.00 | |
| | Miscellaneous Hardware, Tray and 4/0 Grounding | $7.50 | $7.50 | $15.00 | |
| | **Sub-Total** | **$403** | **$89** | **$492** | **$450-$600** |
| 10% | **Contingency** | **$40** | **$9** | **$49** | **$45-$60** |
| | **TOTAL Electrical Works** | **$443** | **$98** | **$541** | **$500-$650** |

## Base Existing GT Unit Refurbishment (Contd)

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| BOP Systems | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Fuel enclosure (See Civil/Structural) | | | | |
| | Fuel piping | $60 | $15 | $75 | $60-$90 |
| | Stack removal | $0 | $75 | $75 | $25-$35 |
| | Inergen system | $7 | $3 | $10 | $7-$15 |
| | Lube oil cooler | $130 | $10 | $140 | $75-$175 |
| | **Sub-Total** | **$197** | **$103** | **$300** | **$150-$320** |
| 10% | **Contingency** | **$20** | **$10** | **$30** | |
| | **TOTAL BOP** | **$217** | **$113** | **$330** | **$180-$350** |

| TOTAL DIRECTS | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | **Sub-Total** | **$3,032** | **$764** | **$3,796** | **$3,200-$4670** |
| | **Contingency** | **$201** | **$48** | **$250** | |
| **TOTAL DIRECTS** | | **$3,234** | **$812** | **$4,046** | **$3,500-$5,000** |

| Project Engineering Costs Mechanical | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Project Engineering Costs | | $324 | $324 | |
| | Project Management Costs | | $283 | $283 | |
| | **TOTAL Project Engineering & Management** | **$0** | **$607** | **$607** | **$550-$700** |

| Total Without Transition Replacement | Material | Labour | Total | Range |
|---|---|---|---|---|
| | **$3,234** | **$1,419** | **$4,652** | **$4,000-$5,700** |

## Standby Option – Installing Leased Gas generator and Power Turbine Parts To Reduce Unit Outage

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| Total Without Transition Replacement | Material | Labour | Total | Range |
|---|---|---|---|---|
| | **$3,234** | **$1,419** | **$4,652** | **$4,000-$5,700** |

| Standby Unit Costs - Leased Parts (Substituting Gas Generator & PT During Refurb) | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | **Gas Generator Rental and Use** | $42 | $10 | $52 | |
| | **Power Turbine Rental & Use** | $42 | $11 | $53 | |
| | **Gas Generator Delivery** | $10 | $10 | $20 | |
| | **Power Turbine Delivery** | $10 | $10 | $20 | |
| | **Sub-Total** | **$103** | **$41** | **$144** | **$125-$200** |
| 20% | **Contingency** | **$21** | **$8** | **$29** | |
| | **TOTAL GTG Lease Parts** | **$124** | **$49** | **$173** | **$150-$225** |

| Total Including Lease Parts | Material | Labour | Total | Range |
|---|---|---|---|---|
| | **$3,357** | **$1,468** | **$4,825** | **$4,150-$5,900** |

## Standby Option – Installing Leased Gas generator and Power Turbine Parts To Reduce Unit Outage

## Standby Option –Leased Nearly new 2 x 5 MW GT To Reduce Unit Outage

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| **Total Without Transition Replacement** | Material | Labour | Total | Range |
|---|---|---|---|---|
| | **$3,234** | **$1,419** | **$4,652** | **$4,000-$5,700** |

| | **New GT Replacement During Outage** | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | GT Lease - 2 x 5 MW | | | | |
| | Rental ($/mo/GT=$105k for 2 GT and 10 months) | $2,100 | $0 | $2,100 | |
| | Hourly operation charge (Assume $41/hr/GT x 1/mo x 2 Hrs) | $2 | $0 | $2 | |
| | Delivery to Site (k$/GT) | $70 | | $70 | |
| | Removal from site (k$/GT) | $70 | | $70 | |
| | Mobilization (k$/GT) | $30 | | $30 | |
| | Setup/Commissioning (k$/GT) | | $220 | $220 | |
| | Breakdown/Demob (k$/GT) | $100 | | $100 | |
| | **Sub-Total** | **$2,372** | **$220** | **$2,592** | |
| | Tax 10-15% | $237 | $22 | $259 | |
| | **Sub-Total** | **$2,609** | **$242** | **$2,851** | **$2,500-$3,300** |
| 10% | Contingency | $261 | $24 | $285 | $250-$350 |
| | **TOTAL GT Lease** | **$2,870** | **$266** | **$3,136** | **$2,750-$3,650** |

| | **Site Civil & Structural Works - Rental Unit** | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Geotech Investigation - bearing capacity of soil | $0 | $4 | $4 | $3-$10 |
| | Pre-engineered shelter for elec. equipment | $40 | $5 | $45 | $37-$55 |
| | Concrete cable trench | $60 | $10 | $70 | $60-$85 |
| | **Sub-Total** | **$100** | **$19** | **$119** | **$100-$150** |
| 10% | **Contingency** | **$10** | **$2** | **$12** | **$10-$15** |
| | **TOTAL Civil Works - rental Unit** | **$110** | **$21** | **$131** | **$110-$165** |

| | **Electrical Systems - Rental Unit** | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | 3c500 kemil, Teck 15kV cable | $112.8 | $10.0 | $123 | |
| | 13.8kV isolating switchgear (3+1 fused switch) | $95.0 | $10.0 | $105 | |
| | P&C/DCS interface | $55.0 | $10.0 | $65 | |
| | 10 x 3c12AWG, Teck, 1000V cable | $1.0 | $2.3 | $3 | |
| | 2 x 25c16AWG, Teck, 1000V cable | $8.5 | $3.2 | $12 | |
| | 4 x 4c12AWG, Teck, 1000V cable | $3.3 | $6.3 | $10 | |
| | 1 x 12C12AWG, Teck, 1000V cable | $2.2 | $1.6 | $4 | |
| | 3c2AWG, Teck, 15kV cable | $0.9 | $0.3 | $1 | |
| | 2 x 3c1/0, Teck, 1000V cable | $4.5 | $1.1 | $6 | |
| | 112kVA, 13.8kV:575V, 3ph, 60Hz transformer | $30.0 | $3.0 | $33 | |
| | 200A, 600V, 3ph, 60Hz automatic transfer switch | $5.3 | $1.5 | $7 | |
| | 200A, 600V, 3ph, 60Hz manual transfer switch | $2.0 | $1.0 | $3 | |
| | MCC, 600A, 600V, 3ph, 3W | $30.0 | $5.0 | $35 | |
| | 30kVA, 575:120/280V, 3ph, 60Hz transformer | $1.0 | $0.5 | $2 | |
| | 129VDC distribution panel, motor starters and disconnects | $35.0 | $6.5 | $42 | |
| | 100A, 120/208V, 3ph, 60Hz distribution panel c/w breakers | $1.4 | $0.4 | $2 | |
| | 600V, battery charger, 129VDC output | $16.0 | $3.2 | $19 | |
| | 129VDC battery bank | $39.0 | $7.5 | $47 | |
| | All interconnecting cabling | $16.0 | $12.0 | $28 | |
| | Miscellaneous 4/0 ground wire, conducts trays and hardware | $16.0 | $9.0 | $25 | |
| | Reconfiguration of DCS screens, conducts and existing system | $0.0 | $25.0 | $25 | |
| | 25kVA, 13.8kV, 3ph, 60Hz, zig-zag grounding transformer | $31.0 | $2.0 | $33 | |
| | Commissioning | **$0.0** | **$63.0** | $63 | |
| | **Sub-Total** | **$506** | **$184** | **$690** | **$650-$800** |
| 10% | Contingency | $51 | $18 | $69 | $65-$80 |
| | **TOTAL Electrical Works - Rental Unit** | **$557** | **$203** | **$759** | **$725-$880** |

## Standby Option –Leased Nearly new 2 x 5 MW GT To Reduce Unit Outage (Contd)

### Capital Cost
### Existing Gas Turbine Generator and Major Auxiliaries.

**Capital cost estimate $ ,000 Can 2011**

| BOP Systems - Rental Units | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | 3" supply and return fuel line | $55 | $22 | **$110** | |
| | **Sub-Total** | **$55** | **$22** | **$110** | **$100-$125** |
| 10% | Contingency | $6 | $2 | $11 | $10-$13 |
| | **TOTAL BOP Rental Units - Rental Unit** | **$61** | **$24** | **$121** | **$110-$138** |

| TOTAL DIRECTS - Rental Units | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | **Sub-Total** | **$3,270** | **$467** | **$3,770** | **$3,500-$4,000** |
| | Contingency | $327 | $47 | $377 | $250-$500 |
| **TOTAL DIRECTS - Rental Units** | | **$3,597** | **$514** | **$4,147** | **$3,750-$4,500** |

| Project Engineering & Management Costs - Rental Units | | Material | Labour | Total | Range |
|---|---|---|---|---|---|
| | Project Engineering Costs | | $332 | **$332** | |
| | Project Management Costs | | $290 | **$290** | |
| | **TOTAL Project Engineering & Management - Rental** | **$0** | **$622** | **$622** | **$500-$750** |

| | Material | Labour | Total | Range |
|---|---|---|---|---|
| **Sub-Total Rental Units** | **$3,597** | **$1,136** | **$4,769** | **$4,250-$5,550** |

| | Material | Labour | Total | Range |
|---|---|---|---|---|
| **Total Including Rental Unit** | **$6,830** | **$2,555** | **$9,421** | **$8,400-$11,500** |

# APPENDIX 8
# DRAWINGS FROM HYDRO

The following drawings will be provided to CONSULTANT for information during the PROJECT:

Holyrood Generating Station - Stage 1 238 - 13 - 3000 – 003 Gas Turbine Unit Relaying and Metering 3 Line A.C. Schematic
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 4 Control & Protection, Turbine &Generator Wiring Diagram (5 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 3 Termination Assembly Layout and Wiring Diagram (Sheet 4A of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 3 Control & Protection, Turbine &Generator (4 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 2 Termination Assembly Layout and Wiring Diagram (Sheet 3A of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine Unit - Cabinet No. 2 Control & Protection, Turbine & Generator Wiring Diagram (3 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 1 Termination Assembly Layout and Wiring Diagram (Sheet 2A of 5)
Holyrood Generating Station 238 - 13 3000 – 007 Panel, Control & Protection, Turbine and Generator Cabinet No. 1 Wiring Diagram (Sheet 2 of 5)
Holyrood Generating Station 238 - 13 - 3000 – 007 Gas Turbine - Cabinet No. 5 DCS Layout and Wiring Diagram (Sheet 7)
Holyrood Generating Station 238 - 13 - 3000 – 008 Gas Turbine Unit Interconnections, Site Wiring Diagram (Sheet 1 of 3)
Holyrood Generating Station 238- 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 1 of 6)
Holyrood Generating Station 238- 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 2 of 6)
Holyrood Generating Station 238 - 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 3 of 6)
Holyrood Generating Station 238- 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 4 of 6)
Holyrood Generating Station 238 - 13- 3000-010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 5 of 6)
Holyrood Generating Station 238 - 13 - 3000 – 010 Gas Turbine Unit Control & Protection Schematic Diagram (Sheet 6 of 6)
Holyrood Gas Turbine 238- 13- 2000- 016 Phasing Diagram
Holyrood Generating Station 238 - 13 - 2000 – 015 Gas Turbine Station Services Panel No. 2 Wiring Diagram
Holyrood Gas Turbine 238 - 13 - 2000 – 014 Exciter & A.V.R. Control Schematic Diagram
Holyrood Gas Turbine 238- 13-2000-013 Avon Start System Connection Diagram
Holyrood Generating Station - Gas Turbine 238 - 13- 2000- 012 575 Volt Motor Control
3 Phase AC. Schematic
Holyrood Generating Station - Gas Turbine 238 - 13- 2000-011 230 V, *30,* AC & 1 1OV DC Auxiliaries Control Schematic
Holyrood Generating Station - Gas Turbine 238 - 13 - 2000 – 010 575 V, *30,* Station Service Supplies and Auto Transfer Switch Control Schematic
NL and Labrador HYDRO 238 - 13- 2000- 017 Wiring Schedule (Sheets 1-28)
Holyrood Generating Station 238 - 13- 0310 -204 Station Service Units 1 & 2, Gas Turbine 4160V Breakers Auxiliary Relay Schematic (Control)
Holyrood Generating Station 238 - 08 - 2000 – 006 Gas Turbine Building Mechanical Equipment
Holyrood Thermal Plant 238 - 08 - 2000 – 007 Gas Turbine Building Modifications to Generator Cooling Air Exhaust Dampers
Holyrood Generating Station 238 - 08 - 2000 – 008 Gas Turbine Avon Vent Ducting

Holyrood Gas Turbine 238 - 08 - 2000 – 009 Compressed Air System Single Line Diagram
Holyrood Generating Station 238 - 13 - 3000 – 009 Gas Turbine Unit Junction Box, Assembly Arrangement of Air Piping 238 - 13- 6010- 015 For A.P.I. Gas Turbine (Sheet 1 of 3)
Holyrood Generating Station 238 - 13 - 3000 – 002 Gas Turbine Unit Panel, Control and Protection, Turbine & Generator
Holyrood Generating Station 238 - 13 3000 – 004 Gas Turbine Unit Junction Box, Pressure Switch, Assembly
Holyrood Generating Station 238 - 13 - 3000 – 005 Gas Turbine Unit Junction Box, Assembly
Holyrood Generating Station 238 - 13 - 3000 – 006 Gas Turbine Unit Junction Box, Assembly
Gas Turbine Generator Transformer Outline 238 - 13 - 6030 - 007R2 Halon 1301 Fire Extinguishing System Layout, 238 - 13- 3003- 001 Turbine & Generator Rooms
Holyrood Generating Station Fire Alarm/Halon Release 238 - 13 - 3003 – 002 Electrical Layout
Holyrood Generating Station Fire Alarm/Halon Release 238 - 13 - 3003 – 003 Control Panel Wiring Diagram
Holyrood Generating Station Holyrood Generating Station 238 - 13- 3000- 001 Gas Turbine Unit Interconnections, Site, Control System
Holyrood Thermal Plant 238 - 08 - 2000 – 001 Gas Turbine Building Outline of Exhaust Gas Stack
Holyrood Thermal Plant 238 - 08 - 2000 – 003 Gas Turbine Stack Support Steel (Original)
Holyrood Thermal Plant 238 - 08 - 2000 – 004 Gas Turbine Building Mechanical Equipment Mounting Details
Holyrood Generating Plant 238 - 04 - 2000 – 001 Proposed Building - Gas Turbine Floor Plan - (Electrical Equipment)
Holyrood Thermal Plant 238 - 08 - 2000 – 002 Gas Turbine Building Volute Exhaust Flange
Holyrood Generating Plant 238 - 04 - 2000 – 002 Proposed Building - Gas Turbine Elevations
Holyrood Thermal Plant 238 - 04 - 2000 – 003 Gas Turbine Building Roof Plan and Elevations
Holyrood Thermal Plant 238 - 04 - 2000 – 005 Gas Turbine Building Structural Steel Framing Plan
Holyrood Thermal Plant 238 - 04 - 2000 – 004 Gas Turbine Building Foundation Plan & Details
Holyrood Thermal Plant 238 - 04 - 2000 – 007 Gas Turbine Building Floor Plan and Section
Holyrood Thermal Plant 238 - 04 - 2000 – 008 Gas Turbine Building Miscellaneous Details
Holyrood Generating Station 238- 13- 0310-019 Gas Turbine Fuel Totalizer
Stack Cap (Snow Doors) 238 - 08 - 3001 – 001 Expansion Joint Fabric (Type C) Rectangular 238 - 08 - 3001 - 002
Holyrood Gas Turbine 238 - 13 - 2000 – 003 Single Line Diagram
Holyrood Thermal Plant 238 - 13 - 2000 – 004 Gas Turbine Building Grounding Layout
Holyrood Thermal Plant 238 - 13- 2000 – 005 Gas Turbine Building Conduit Layout & Details
Holyrood Gas Turbine 238 - 13 - 2000 – 001 Metering and Protection Single Line Diagram
Holyrood Gas Turbine 238 - 13 - 2000 – 006 Rehabilitation Project Schedule
Holyrood Thermal Plant 238 - 13 - 2000 – 007 Gas Turbine Building Lighting and Heating Layout
Holyrood Generating Station 238 - 13 - 2000 – 008 575 V, *30,* 230,1 iSV, 10 & 110 V D.C. Dist. PNL.'s 575V, 3 Phase Light Oil Transfer Pump
Holyrood Generating Station - Gas Turbine 238 - 13 - 2000 – 009 A.C. and D.C. Station Service Supplies Single Line
Holyrood Gas Turbine 238 - 13 - 6010 – 047 A.P.I. Governing & Control System Arrangement of Air Piping for A.P.I. Gas Turbine 238- 13- 6010-015 (Sheet 2 of 3)
Arrangement of Air Piping for A.P.I. Gas Turbine 238- 13-6010-015 (Sheet 3 of 3)

# APPENDIX 9
# BRADEN MANUFACTURING SITE SERVICE REPORT

# APPENDIX 10
# GREENRAY TURBINE SERVICE REPORT

# APPENDIX 11
# SIEMENS HRD CONDITION ASSESSMENT AND BUDGET PRICING

# APPENDIX 12
# ROLLS WOOD GROUP FIELD SERVICE REPORT

# NEWFOUNDLAND & LABRADOR HYDRO

## Snook's Arm Wood Stave Penstock

## Evaluation, Recommendation and Estimated Cost for Replacement



**Prepared By:**

**Newfoundland and Labrador Hydro**
**Generation Engineering**

**January 26, 2004**

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Appendix A
Map of Snook's Arm Penstock

Appendix B
Photos

Appendix C
Detailed Economic Analysis

Appendix D
Project Schedule

## 1.0 Introduction

.1 Project Location

The Snook's Arm hydroelectric development is located on the Baie Verte Peninsula, approximately 80 km from the Trans Canada Highway. A map showing the location of the penstock in relation to the community of Snook's Arm is provided in Appendix A.

.2 Project Description

.1 General

The hydroelectric development was constructed in 1956 for the Maritime Mining Corporation and was purchased by Newfoundland & Labrador Hydro in 1968. The development has a watershed of approximately 11.8 $mi^2$ and includes Armchair Pond, Red Cliff Pond, West Pond and East Pond. The main dam and intake is located on the south side of East Pond. The unit has a rated output of approximately 590 kW and produces an average of 3,500,000 kWh/year.

.2 Penstock

The penstock was built in 1956 by the Pacific Coast Pipe Co. The penstock has an inside diameter of 30" and a length of 3050 ft.

The wood staves were machined from nominal 2" x 4" Douglas Fir with tongue and groove radial side joints, double tenon end joints, and creosote pressure treated to 8 $lbs/ft^3$ net retention or rejection. As a result of damage during shipment, many stave ends (double tenon end joints) were cut square and field jointed with metal splines.

The bands are ½" dia x 9-2" long, 1 piece with button head one end and rolled thread on the other, and ½" x 36" pipe shoes. There are approximately 12,000 steel bands with spacing varying from 10" on centre at the intake to 3" on centre at the powerhouse. The penstock is supported on chock block cradles (6" x 6" chock on 4" x 6" sill) on 8-foot centers.

There is a 4" air release valve and a 4" drain valve on the line.

.3 Summary of Reports

Several reports have been prepared over the years, describing the condition of the penstock and associated components. These reports have been used to determine the problems that have been identified over the years and the condition of the penstock. The reports include:

Inspection Report of Venam's Bight and Snook's Arm Wood Stave Penstocks, Prepared by Canbar Inc., Sept. 3-4, 1998.

Inspection Report of Venam's Bight and Snook's Arm Wood Stave Penstocks, Prepared by Canbar Inc., Aug. 15-16, 2000.

Snook's / Venam's Penstock, Prepared by L. Kearley, Civil Technologist - Newfoundland & Labrador Hydro (Interoffice Memo), April 12, 2001.

Snook's Arm Penstock Enclosure, Prepared by G. Poole, P. Eng. - Newfoundland & Labrador Hydro (Interoffice Memo), June 28, 2001.

Snook's / Venam's Penstock Assessments, Prepared by L. Kearley, Civil Technologist - Newfoundland & Labrador Hydro (Interoffice Memo), Dec. 21, 2001.

.4 Maintenance History

Detailed records of maintenance history were not kept or are unavailable, however, since the early 1990's significant efforts have been undertaken to maintain the penstock. This includes:

- Patching of leaks;
- Replacement and addition of steel bands;
- Repair and replacement of penstock cradles;
- Removal of vegetation and growth;
- Improvement of drainage around penstock.

## 2.0 Identified Problem Areas

Described below are areas of the penstock that have been identified as problem areas.

.1 Penstock Design and Profile

The wooden penstock is 3050 ft long and has a head of 300 ft and there is no surge tank available. The lack of a surge tank causes limitations on the operation of the Plant and also stresses the penstock. In the event of a unit trip, a sudden water hammer surge would occur, which causes pressure on the joints between the wooden staves. Typically after such a water hammer event, additional leaks appear in the penstock.

The penstock profile has several flat sections and one reverse section in the mid to upper half of the penstock, see photos #1 & #2. The reverse grade increases the probability of the penstock collapse during operation, when the Plant is fully loaded. The only protection from collapse is a vacuum breaker valve located at the mid-point of the line. This valve is designed to break any vacuum that may cause a collapse. It is critical that this valve is kept in good working condition to ensure that it will operate as required. Recent problems experienced include a fire in the valve enclosure and a malfunction of the valve.

.2 Penstock Material

The penstock is constructed from 2" x 4" Douglas fir timbers machined to create the diameter of the penstock. Steel bands spaced on 3" – 10" centers, hold the wood stave material together and maintain the shape of the penstock.

.1 Wood Staves

Various inspections of the penstock have indicated that there is joint leakage between the staves, brooming at stave ends and between steel bands and crushing of the staves along the spring line or top of the penstock. The brooming and crushing is worse at the lower end of the penstock, which is subject to higher pressures. The crushing and brooming indicates delamination between the wood fibers and deterioration of wood, see photos #3 & #4. The rate and areas of deterioration continues to grow with the age of the structures.

Also along the length of the penstock, areas of moss and other vegetation are growing directly on the penstock; see photos #5 & #6. Vegetation growth typically retains moisture and cause stave deterioration. In some cases the vegetation can be parasitic to the wood stave. Vegetation thrives because of continuous water supply leaking from the penstock. The cost of removing the vegetation continues to increase.

.2 Steel Bands

There are approximately 12,000 steel bands used to maintain the shape and integrity of the penstock. All of the bands show various signs of rusting, corrosion and deterioration. Also, in recent years some bands have been observed with significant corrosion below the threads on the band, see photos #7 & #8. These bands are required to be replaced or new ones installed adjacent to the old ones (where possible). In addition, there is bright, visible corrosion on the majority of the steel bands that do not receive direct sunlight. These areas include the penstock enclosure, buried section of the penstock and at the road crossings. In these same areas it is difficult if not impossible to replace the steel bands because of the limited access. Also, in several locations it is impossible to replace the bands unless the penstock is dewatered, because of the decreased band spacing and the higher pressure on the lower half of the penstock. However, frequent dewatering of the penstock is not recommended because of its aged and deteriorated condition.

.3 Leaking Water from Penstock

Leaking of the penstock joints have been observed since at least 1968, see photos #9, #10 & #11. The leaks were sometimes repaired by driving nails into the leaking area, this method however tends to promote deterioration of the wooden staves, see photo #12. The more common method of sealing the leaks involved the installation of small steel plates under the existing steel bands or by adding new bands between the existing ones in the area of the leak, see photo #13. The penstock has been dewatered approximately 4-5 times since 1989 to repair the leaks. During one event, the penstock was dewatered for approximately 5-6 days, which allowed the wood staves to dry out and shrink in size. When the penstock was watered up there were a significant number of additional leaks of various sizes, which required lengthy time and effort spent to correct and seal the new leaks. Based on this experience, the penstock has been dewatered and watered up during the same day to repair any leaks in the penstock. However, each time the penstock is dewatered, additional leaks appear when the penstock is watered up again. Overall, the dewatering of the penstock is a significant activity that creates just as many or more leaks than those that are repaired.

The leakage of water from the penstock has caused an accelerated rate for:

- Wood penstock to deteriorate;
- Metal bands to corrode and rust;
- Increase growth of vegetation;
- Deterioration of wood supports and enclosures; and
- Increase maintenance cost for control, sealing and patching of leaks.

.4 Ice Buildup

All leaks from the penstock result in significant ice formation during the winter. The ice formations are becoming an increasing problem for Hydro because of its danger/risk to local residents.

The formation of ice was investigated during the winter of 2001 and several observations were made. The ice formations were fed from the penstock by the constant flow of running (leaking) water. The ice formations extended down over the sides of the penstock to the ground. One ice formation observed was 8 ft high and 3 ft long at its base, the average ice formation was 5 – 6 ft in height, see photo #14. The danger caused by the ice formations is that the ice loads or large ice chunks could severely damage or rupture the weakened penstock. Another key area of ice formation was under the penstock enclosure. The leaking water causes large ice formations under the enclosure around the area of the access road, see photo #15. Besides adding a substantial load to the penstock and its support structure, it also interrupts local traffic (this sometimes leads to unsupervised demolition of the ice).

.5 Steel Section of Penstock

The first section of the penstock, from the intake to approximately 80 ft downstream, is fabricated from riveted steel plate; refer to location #1 on map SA-1 and photos #16 & #17. Because of the age of this steel section of penstock plus the fact that it has been partially or totally submerged for years, it continues to deteriorate. In addition, the concrete saddles for this section are also damaged. This section of penstock will likely be required to be replaced at the same time as the adjacent wooden penstock.

.6 Enclosure Over Access Road

There is a section of the penstock, located just above the community, which crosses over a small access road, refer to location #2 on map SA-2. There are two critical areas with this location; the support structure and enclosure, see photos #18 & #19.

.1 Support Structure

The support structure for the penstock is supported by 8" x 8" timbers at roughly 8.5 ft centers. At the upstream end, the enclosure is practically on the ground and it rises off the ground until it reaches the road where it is supported 10 ft off the ground by 8"x 8" and 6" x 6" timbers. The penstock is supported horizontally by two poles spanning the road. Some of the timbers appear to be creosote treated while others do not show any signs of protective coating. This structure is original and is showing its age. This structure supports the penstock, the enclosure, snow loads and substantial ice loads, while providing daily access to local residents.

.2 Penstock Enclosure

The penstock is enclosed for a length of 75 ft in the vicinity of the access road; the enclosure was built to reduce ice formation during the winter. The penstock invert was heat traced to reduce ice buildup inside of the structure; however, ice buildup inside and outside of the enclosure is still an ongoing problem. There are several concerns associated with this structure including the old and deteriorated condition of the enclosure, reliability of the heat tracing, and the limited access for inspection and maintenance of the penstock inside the enclosure. In general, the structure is becoming more of a safety concern as it ages.

.7 Buried Section of Penstock

The penstock passes through the middle of the community and at times, is within a few feet of the adjacent houses; see photos #20 & #21. Also a considerable length of the penstock, approx. 200 ft is buried, refer to location #3 on map SA-2 and see photo #22. In 1998, a section of the buried penstock was excavated and it was observed that the penstock is supported on cradles, similar to the rest of the penstock. Buried penstocks are designed to be fully supported along their length, the discovery of cradles supporting the penstock in the buried section, suggests that the penstock was not designed to be buried. The burial of the penstock subjects it to additional loads from the overburden soil and live loads from vehicles, skidoos, woodpiles, etc. In addition, there is very poor drainage around the penstock causing the penstock to be submerged in water. The risk associated with this section of penstock is high because of additional loading, moist conditions and lack of maintenance; there is a high probability of failure of this section of the penstock.

.8 Road Bridge

A section of the penstock (approximately 30 ft) crosses under the main access road through the community, refer to location #4 on map SA-2. There are two key items at this location, the support structure and penstock condition.

.1 Bridge Structure

Some of the existing bridge components were constructed in 1971 and they are showing obvious signs of deterioration. The bottom section (approx. lower ¾) of the bridge abutments are constructed from local untreated timbers and they are deteriorating, see photo #23. It appears that the only thing keeping the abutments from collapsing is a framework of pressure treated timber braced between the existing abutments, which were installed several years ago, see photo #24. The department of Works, Services and Transportation have indicated that they have no plans to replace this structure in the near future.

.2 Penstock

It is extremely difficult to inspect the condition of the existing penstock due to the limited access under the bridge and around the penstock. However, from the limited inspections it has been observed that several steel bands are severely deteriorated and there are several leaks. There has been very little or no maintenance to this section of the penstock because of the limited access.

.9 Road Crossings

There are a total of four locations where the penstock crosses various access roads. Two of the four have been identified above (penstock enclosure and road bridge), at the remaining two locations the penstock passes under the roads. The first location is near the intake and is the access road for the Nugget Pond gold mine and was constructed in the early 1990's. The penstock is enclosed in a culvert for a length of 65 ft. The second location is near the powerhouse and crosses the main access road to the community. The penstock is buried for a length of 130 ft. At this location, the penstock is buried and is heavily covered in vegetation. The type of structure used to protect the penstock from additional loads caused by the road crossing is unknown, however, it is assumed to be a culvert. In both of these locations it is impossible to inspect or perform any maintenance on the wooden penstock or steel bands.

.10 Penstock Coating

The original wooden penstock components were coated with creosote to provide protection from deterioration and sunlight. Typically a wood penstock would be recoated with creosote every 5-10 years to maintain the protective coating. This penstock has not been coated for at least 15 years (due to environmental restrictions on the use of creosote) and as a result the majority of the wooden penstock has no protection coating, especially along the top, see photo #25. The lack of protective coating has accelerated the deterioration of the wooden staves.

.11 Use by Residents of Community

As indicated earlier, the penstock passes through the community and in several locations the penstock is within a few feet from homes and roadways. The proximity of the penstock to the homes has encouraged many residents to tap into the penstock for a source of water, see photos #26 & #27. These taps were constructed without any permission from Hydro and in several locations have been abandoned and leaking water, see photo #28. In addition, all terrain vehicles and skidoos travel over and under the penstock, which imposes additional loads and stresses on the penstock. In the upper half of the penstock, there is firewood stacked adjacent to the penstock, see photo #29, and in several places there are cuts in the penstock from chainsaws. The use

(or abuse) of the penstock by local residents has lead to increased deterioration of the penstock.

.12 Summary

A significant number of these identified problems are located in the high-pressure section of the penstock that runs through the community. In addition, there is more than 300 feet of covered or buried penstock, located within this section, which had very minimum maintenance over the years due to the limited access. This section has a potential for high liability in case of a failure.

## 3.0 Significant Historical Events

During the operating history of the Plant, several events have occurred which have caused damage or had potential to damage the penstock.

.1 Flood Damage – 1992

The lower section of the penstock passes under the main access road to the community and then proceeds along the side of a brook towards the powerhouse, refer to location #5 on map SA-2. In 1992 high water levels in the brook caused a section of the embankment under the penstock to erode. Untreated timber cribbing was installed along side of the brook to support the penstock, see photos #30 & #31. The timber support is 15 years old and is still subject to brook damage. The penstock has also developed a noticeable dip in elevation at this location resulting in more leaks.

.2 Flood Damage – 1996

In 1996 water overtopped Snook's Arm main dam and caused flooding downstream. The flooding caused a 200 ft section of the access road to the Nugget Pond gold mine to be washed away. The flooding caused a significant amount of rock and debris to move downstream and adjacent to the penstock. Though, the majority of the rock debris was removed, however some of the rocks remain next to the penstock, see photos #32 & #33. This rock debris probably has and will continue to impose stresses on the penstock and, which over time, may displace the penstock transversely. Another similar event would likely have a major impact on this section of the aged and weakened penstock.

.3 Fire Damage

In 2002 a fire occurred in the valve enclosure around the vacuum breaker valve, see photos #34 & #35. The fire was caused by a malfunction of the heat tracing and caused the destruction of the valve enclosure and damage to the valve. Luckily, there was no apparent damage to the penstock. However, the vacuum breaker valve did require repair. And, as stated earlier, if this valve fails to operate when required, the penstock may collapse.

## 4.0 Reliability

.1 General

Wooden stave penstocks typically have a design life of 40 years. The Snook's Arm penstock has been in operation since 1956. Numerous assessments of the penstock condition have been conducted and are summarized in Table 1.

| Report | Author | Date | Comments |
|---|---|---|---|
| Inspection Report of Venam's Bight & Snook's Arm Penstocks | Canbar Inc. | Sept. 1998 | "This pipe is 42 years old but is still expected to provide several more years of service, provided proper maintenance practices are still observed." |
| | | | |
| Inspection Report of Snook's Arm & Venam's Bight Penstocks | Canbar Inc. | Aug. 2000 | "Should icing up become unmanageable or potential liability become significant, due consideration should be given to the replacement of all or part of this pipe prior to the end of the pipe's otherwise practical and safe service life." |
| | | | |

Table 1: Summary of Penstock Inspection Reports and Recommendations

.2 Summary

The normal design life of most wooden penstocks is 40 years. This penstock is 47 years old and when replaced, in 2006, will be 50 years old.

This penstock is significantly beyond its original design life, has many identified problem areas, continues to deteriorate and maintenance costs are increasing. The probability of failure and its impact on generation, as well as, loss of life and property will continue to increase. It is recommended to replace the penstock as soon as possible.

## 5.0 Safety

.1 General

The penstock is 3050 ft long and approximately half of its length travels through the community. In several places it is only a few feet away from adjacent homes. The penstock is 47 years old and considering its age, condition and known problems, the probability of failure is increasing with time.

.2 Failure Analysis

A computer simulated failure of Snook's Arm main dam was completed in 2001 and revealed that there would be potential damage to structures and injury to those individuals in the immediate area. The majority of the flooding may be confined to the river valley that runs along the east side of the community and the area around the harbour.

A major break in the upper portion of the penstock is expected to cause flooding in a similar area to that of a dam failure. Damage would also be expected to occur to the balance of the penstock and to nearby property.

However, if a major break occurred in the lower half of the penstock, it is expected that the water would flow through the middle of the community. Due to the proximity of the homes adjacent to the penstock, it is expected that significant property damage and personal injury would occur.

It is important to note that the extent of flooding would depend on numerous factors, including:

- Time of year;
- Time of day;
- Weather conditions;
- Location of break or leak;
- Time between break occurring and break detected;
- Amount of time between break and stopping flow of water.

.3 Summary

As the age of the penstock increases so does the probability of a major break. It is recommended to replace the penstock as soon as possible.

## 6.0 Alternatives

.1 General

The penstock is currently 47 years old and beyond its normal design life. It has deteriorated and must be replaced. The following alternatives were studied:

i.) Do Nothing;
ii.) Retire Plant;
iii.) Replace Penstock;
iv.) Phased Replacement of Penstock.

.2 Do Nothing

This alternative is available in any project. However, in this case, a break in the penstock is most likely to occur in the lower section of the penstock, which is subject to the highest pressure. Due to the proximity of the community to the lower half penstock, significant damage would occur to private property, community infrastructure and the potential exists for personal injury. Based on this risk to Hydro, this alternative is not recommended.

.3 Replace Entire Penstock

This alternative would involve replacing the existing penstock with a new penstock from the intake to the Plant. The detailed design for the new penstock would consider the least cost consistent with reliable service. The material used may be steel, fiberglass or high-density plastic products. The estimated cost for the replacement penstock with steel in 2006 is $1,930,000 (in 2003 dollars).

.4 Phased Replacement of Penstock

Under this alternative the penstock will be replaced in two phases. The lower, high-pressure section of the penstock which runs through the community (from mid point of the penstock to the powerhouse approximately 1500 ft long) will be replaced in 2006. This would reduce the higher potential liability to Hydro, caused by a failure in the high-pressure section. The design of the phased replacement of the penstock would consider a method(s) to reduce the impact to the community in the event of break in the upper portion of the penstock. In addition, the work will include maintenance to the upper section of the existing wood stave penstock. In the second phase, under this alternative, the upper remaining section of the penstock will be replaced in 2016.

.5 Retire Plant

Under this alternative the existing Plant and associated facilities would be retired. However, there would be a cost associated with the retirement of the Plant, including:

- Removal of powerhouse and equipment;
- Removal of penstock;
- Removal of dam structures (in a controlled manner);
- Remediation of the environment.

It is estimated that it would cost approximately $500,000 to remove the existing structures and remediate the sites. Also, an Environmental Impact Statement would have to be prepared and submitted to the Provincial Government for review and approval.

It is recommended that this alternative be considered for further evaluation.

.6 Environmental Considerations

Snook's Arm generation displaces thermal generation at Holyrood and represents a direct reduction in fossil fuel emissions. With the heightened profile of the Kyoto protocol and other environmental initiatives there will likely be interest in the emissions reductions associated with this and similar projects. The following table presents an estimate of annual $CO_2$, $N_2O$ and $SO_2$ reductions attributable to Snook's Arm.

| Alternative | Estimated Emission Reductions (Tonnes per year) | | |
|---|---|---|---|
| | $CO_2$ | $N_2O$ ($CO_2e$) | $SO_2$ |
| Snook's Arm | 2,796 | 0.06<br>(18) | 32 |

While it is difficult to estimate the exact nature of future emissions control programs and the resulting value of any emissions credits, the following representative values have been used for sensitivity analysis:

- $10/tonne for $CO_2$ based on Government of Canada estimates; and
- $200/tonne for $SO_2$ based on recent emissions trading experience in the US.

## 7.0 Cost Evaluation

.1 General

Four alternatives are identified in the previous section.

Three alternatives, except "do nothing", are further evaluated. Listed below are the cost estimates, assumptions and analysis of the data:

.2 Cost Estimates

Direct capital cost estimates for each alternative is listed in Table 2.

| Alternative | | Est. Cost (2003 $'s) |
|---|---|---|
| | | |
| 1.) | Replace Entire Penstock | $1,930,000 |
| | | |
| 2.) | Phased Replacement of Penstock | $2,140,000 |
| | | |
| 3.) | Retire Plant | $500,000 |

Table 2: Summary of Cost Estimates for Penstock Alternatives

.3 Assumptions

Several assumptions were made in order to complete the cost analysis for each alternative. These include:

- Average escalation rate of 2%;
- Average interest (discount) rate of 8.5%;
- Project contingency rate of 10%;
- Corporate overheads at a rate of 6%;
- Unit Output: 590 kW;
- Average annual production of 3.5 GWh
- Annual Operator Cost: $15,000;
- Annual O & M Costs: $25,000;
- Runner Maintenance: $7,500 every ten years.

Additional assumptions were required for each alternative investigated, these include:

Alternative #1 (Replace Entire Penstock)

- Engineering Costs of $115,000 in 2005;
- Construction Costs of $1,815,000 in 2006.

Alternative #2 (Phased Replacement of Penstock)

- Engineering Costs of $90,000 in 2005;
- Construction Costs of $1,100,000 in 2006;
- Engineering Costs of $50,000 in 2015;
- Construction Costs of $900,000 in 2016;
- Annual penstock maintenance for upper section until replaced in 2016: $20,000.

Alternative #3 (Retire Plant)

- Retire Plant and Remediate Site(s) at a cost of $500,000 in 2006;
- Replace energy from Holyrood.

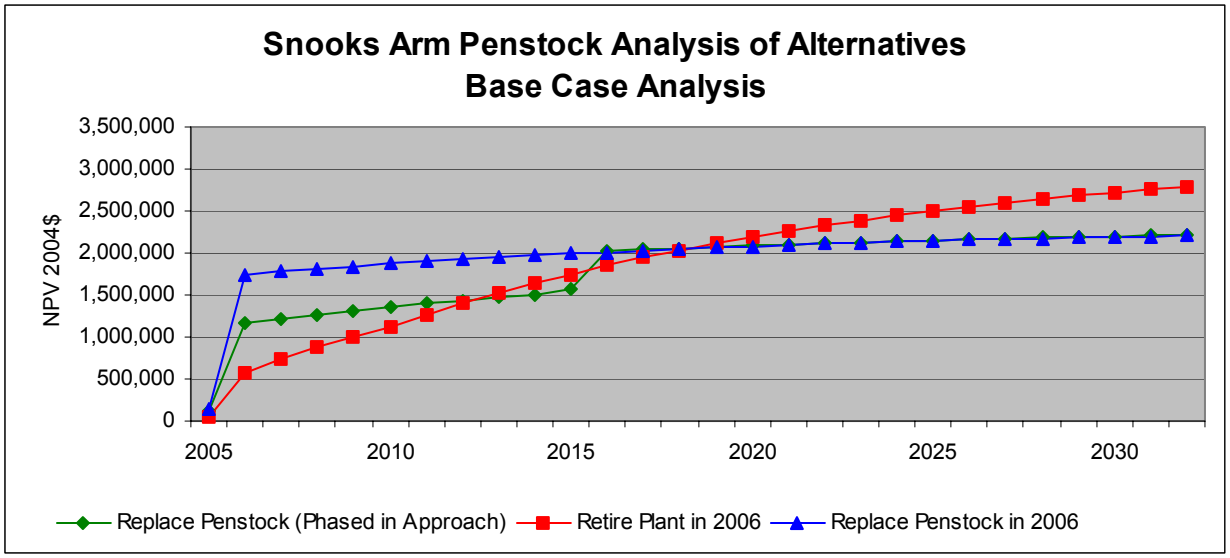
.4 Economic Analysis

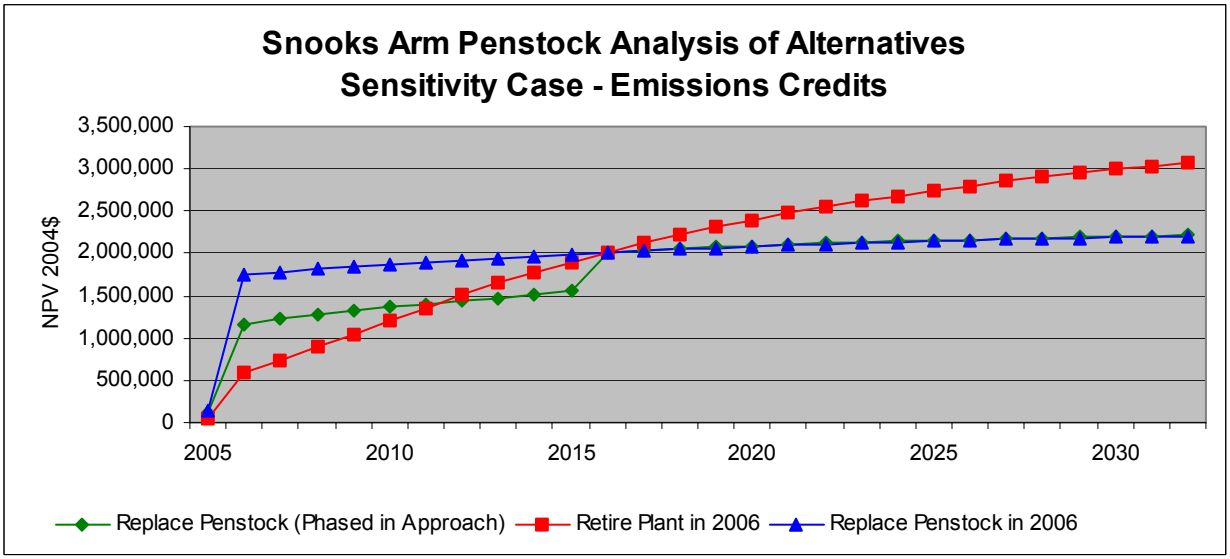
The economic analysis compared the cumulative present worth cost (capital and operating) of each of the penstock replacement alternatives against each other and against the plant retirement alternative. In addition to the base case analysis, a sensitivity case addressing the inclusion of emissions related costs was also prepared.

A summary of the detailed economic analysis found in Appendix C is presented in the following table and the graphs that follow:

Table 7-1

| Snook's Arm Penstock Replacement Comparison of Alternatives | | |
|---|---|---|
| | CPW Preference Against Plant Retirement Alternative | |
| | CPW (2004$) | Payback Period |
| Base Case: | | |
| Full Replacement in 2006 | $585,923 | 13 Years |
| Phased in Replacement (2006 & 2016) | $577,488 | Phase 1 - 7 Years<br>Phase 1+2 – 13 Years |
| Sensitivity Case – Emissions Costs: | | |
| Full Replacement in 2006 | $862,672 | 10 Years |
| Phased in Replacement (2006 & 2016) | $854,237 | Phase 1 - 6 Years<br>Phase 1+2 – 11 Years |




Based on this analysis, it is evident that the replacement of the penstock is preferred over the plant retirement alternative. While the phased in replacement of the penstock shows an initial payback of 7 years on the first replacement phase, the payback on the complete project in both replacement alternatives is 13 years. Further, there is a negligible difference in the cumulative present worth costs of either of the replacement alternatives after 13 years.

Sensitivity analysis indicates that the inclusion of emissions related costs improves the preference for the penstock replacement alternative over the plant retirement alternative and also shortens the payback period for the full replacement alternative by 3 years.

## 8.0 Results

The results of the economic analysis indicated that the phased replacement of the penstock could provide the greatest net positive result. However, there are several disadvantages associated with this alternative, these include:

1. The upper section of the penstock would be 60 years old if replaced in 2016; this will be approximately 20 years beyond the design life of the penstock. Therefore, the upper portion of the penstock will remain a potential liability to Hydro.

2. The phased replacement of the penstock would require the entire penstock to be dewatered. Some method would have to be implemented to ensure the wood staves in the upper portion of the penstock do not dry out. The methods could include installing a bulkhead at the end the section of penstock, to be reused, and then keeping the penstock watered up or installing a sprinkler system (or similar system) to provide a continuous flow of water over the wooden staves. All of the methods would require the existing penstock to be dewatered for some period of time, which will cause some leakage when the penstock is put back into operation.

3. This alternative would also include the construction of a dam or similar structure near the joint between the new and existing penstocks to allow any water from the failure or rupture of the penstock to be diverted away from the community.

4. There would be additional costs associated with the upgrade of the existing penstock in 2006 to ensure an additional ten years of service life. In addition there will be annual operating maintenance costs associated with the existing penstock until it is replaced.

Based on the disadvantages associated with the phased replacement of the penstock, it is recommended that this alternative not be considered.

The next alternative with the greatest net positive result is the entire replacement of the penstock. The advantages of this alternative include:

1. Substantial reduction of potential liability to Hydro from potential failure or rupture of wood stave penstock.

2. Increased reliability of penstock.

3. Decreased energy losses, such as water loss from wood stave penstock and head loss (friction) in new penstock material.

4. Use of a renewable resource;

5. A design life in excess of 30 years for the new penstock;.

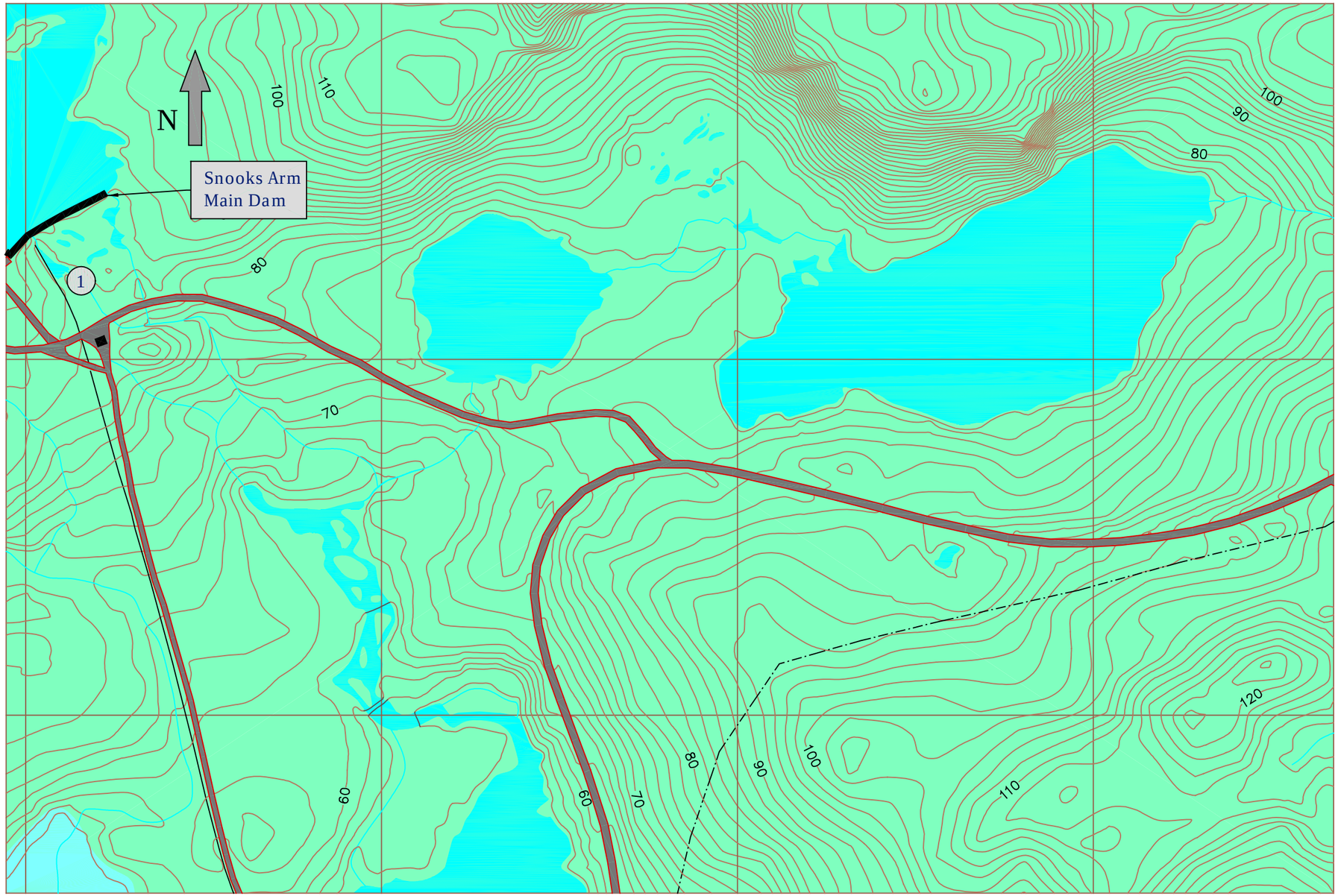
The entire replacement of the penstock will provide the lowest overall cost to Hydro while providing an acceptable level of reliability for the production of electricity.

## 9.0 Recommendations

Based on the review of the available alternatives and the economic analysis, it is recommended to replace the entire Snook's Arm penstock. The design should be completed in 2005 and the replacement completed in 2006. A proposed project schedule for the penstock replacement is included in Appendix D.

# APPENDIX A

# MAP OF SNOOK'S ARM PENSTOCK







LEGEND :

- ROAD
- STREAMS / ORIGINAL WATER LEVEL
- HOUSES / CABINS / BUILDINGS
- 50 — ELEVATION (m)
- WHARFS / PIERS / SLIPWAYS
- PENSTOCK
- 1 — REFERENCE LOCATION

MATCH TO SHEET "SV1-2"

NOTES:

1. MAP ORIGIN, AIR PHOTO AND MAP LIBRARY, GOVERNMENT SERVICES AND LANDS. SCALE 1: 2500 CONTOUR INTERVAL 2 m.

SCALE

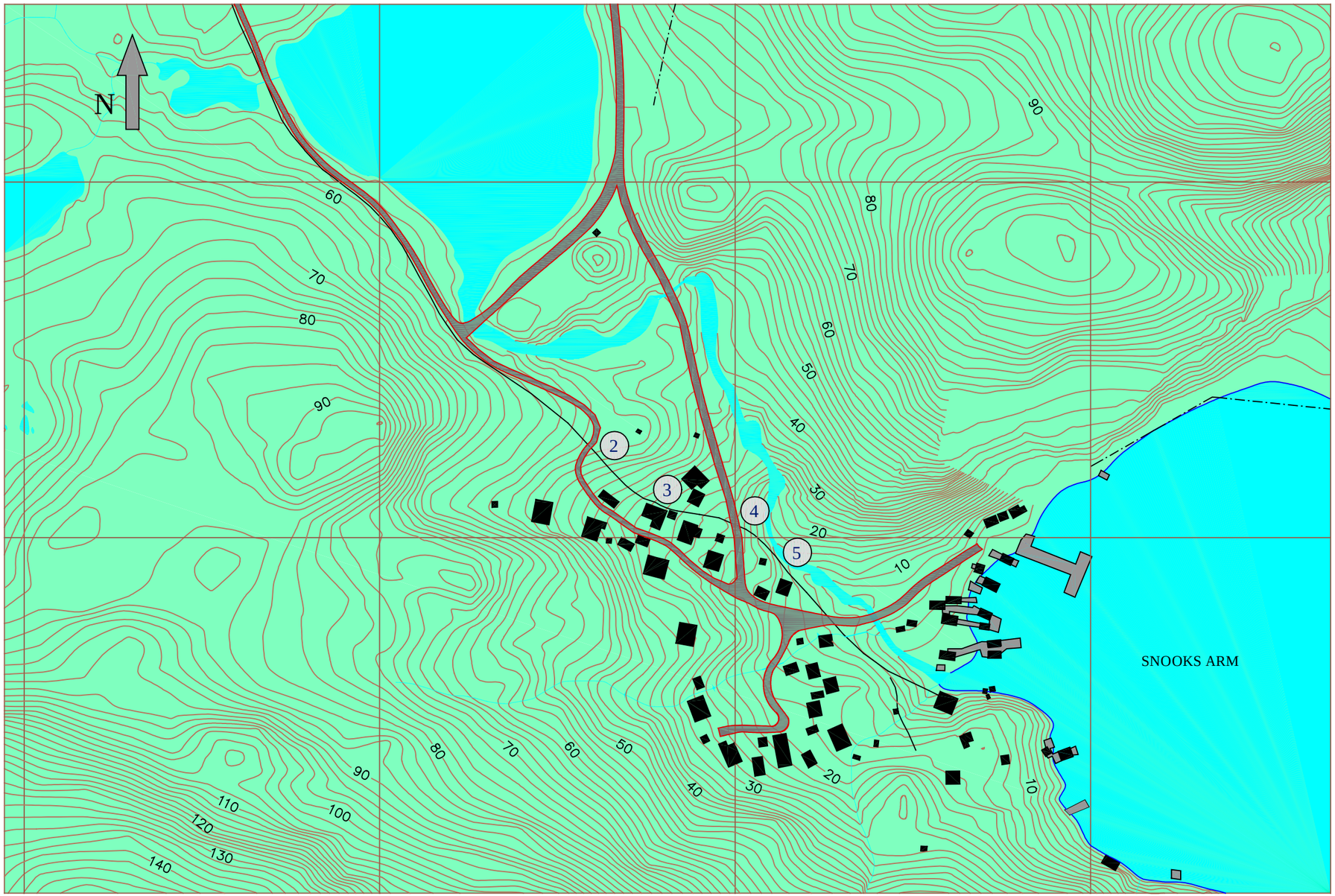
0 100 200 m.

0 500 ft.

NEWFOUNDLAND AND LABRADOR HYDRO

# SNOOKS ARM PENSTOCK
# TOPO MAP
# km 0.0 to km 0.5

| | | |
|---|---|---|
| Date : Mar. 2001 | Design: J. Phillips | Map No. SA-2 |
| Dwn.: D. Oliver | App.: | Sheet 1 of 2 |







LEGEND :

- ROAD
- STREAMS / ORIGINAL WATER LEVEL
- HOUSES / CABINS / BUILDINGS
- 50 ELEVATION (m)
- WHARFS / PIERS / SLIPWAYS
- PENSTOCK
- 1 REFERENCE LOCATION

NOTES:

1. MAP ORIGIN, AIR PHOTO AND MAP LIBRARY, GOVERNMENT SERVICES AND LANDS. SCALE 1: 2500 CONTOUR INTERVAL 2 m.

SCALE

0 100 200 m.

0 500 ft.

NEWFOUNDLAND AND LABRADOR HYDRO

# SNOOKS ARM PENSTOCK
# TOPO MAP
# km 0.5 to km 1.2

| | | |
|---|---|---|
| Date : Mar. 2001 | Design: J. Phillips | Map No. SA-1 |
| Dwn.: D. Oliver | App.: | Sheet 2 of 2 |

# APPENDIX B

# PHOTOS




Photo #1: View of penstock, August 2000.



Photo #2: View of flat and reverse section of penstock, August 2000.



Photo #3: View of brooming between metal bands, August 2000.



Photo #4: View of crushing and brooming of wooden staves, August 2000.



Photo #5: Vegetation growth around and on penstock, June 2001.



Photo #6: Moss and other vegetation growing directly on penstock, June 2001.



Photo #7: View of corrosion below threads, August 2000.



Photo #8: View of corrosion on metal bands, August 2000.



Photo #9: Water leaking from penstock, August 2000.



Photo #10: Water leaking from penstock, August 2000.




Photo 11: View of water leaking from penstock, August 2000.



Photo #12: Nails driven into penstock to stop leaks, June 2001.



Photo #13: Metal patches placed under new bands to stop leaks, October 2003.



Photo 14: Ice formation above penstock, April 2001.



Photo 15: Ice formations under penstock enclosure, April 2001. For location of ice formation refer to Photo #18.



Photo #16: Accumulation of water behind concrete cut-off dam, June 2001.



Photo #17: Steel section of penstock, partially submerged in water, June 2001.



Photo 18: Penstock enclosure over access road, July 2002. Highlighted area indicates location of ice formation shown in Photo #15.



Photo 19: Support structure for penstock enclosure, July 2002.





Photos #20 & #21: View of penstock passing through community, October 1992.



Photo #22 Buried section of penstock in community, June 2001.



Photo 23: View of bottom portion of bridge abutment, June 2001.



Photo 24: Road bridge over penstock, note timber reinforcement between abutments, July 2002.



Photo #25: Loss of protective coating on penstock and bleaching of the wood, August 2000.





Photos #26 & #27: Water take-offs to adjacent homes (left) and Nugget Pond gold mine security building (right), August 2000.



Photo #28: Location of abandoned water tap in penstock, June 2001.



Photo #29: View of access road and firewood adjacent to penstock, August 2000.





Photos #30 & #31: Timber support added under penstock after erosion of embankment, October 1992.



Photo #32: View of rocks and gravel washed up against penstock, April 1996.



Photo #33: View of rocks and gravel under penstock, August 2000.



Photo 34: Fire damage to vacuum breaker valve enclosure, July 2002.

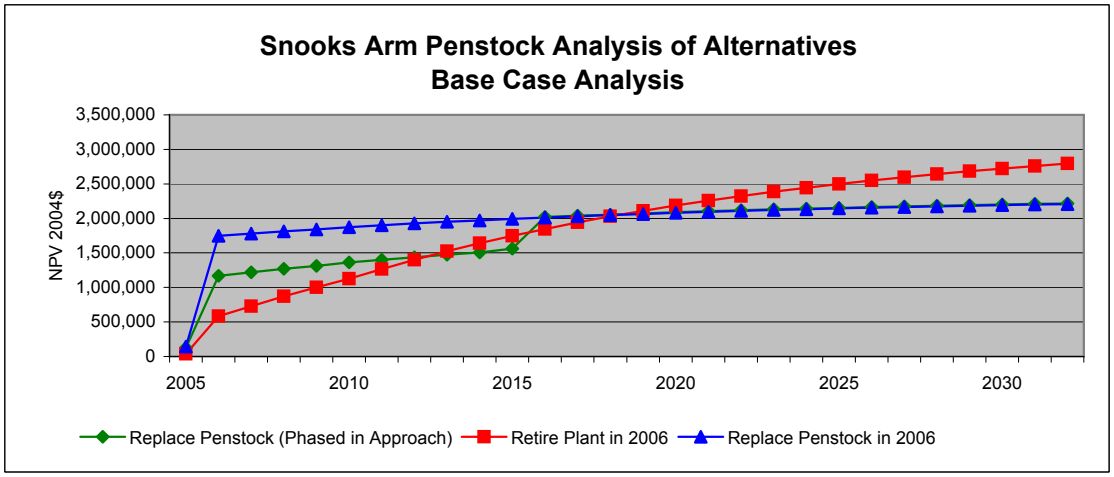


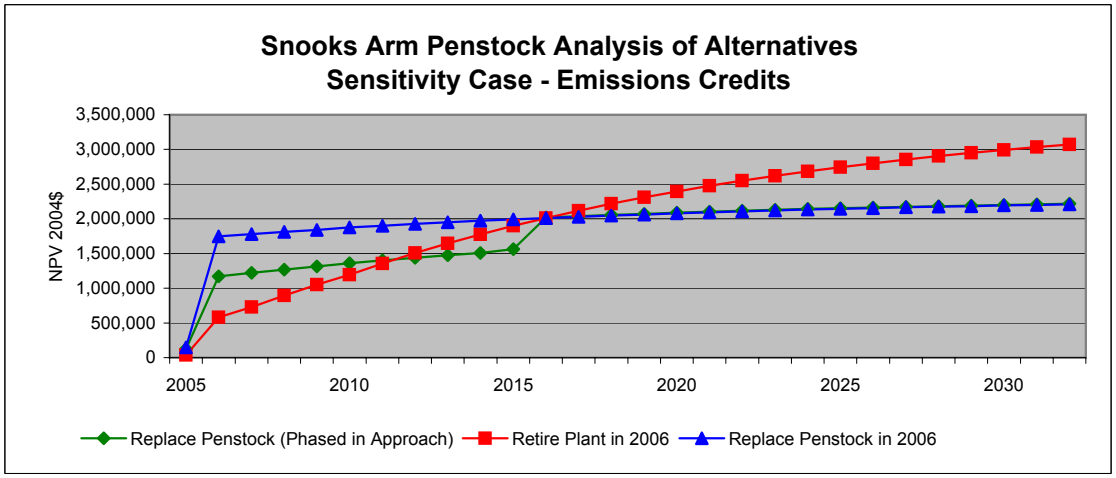
Photo 35: Vacuum breaker valve after fire, July 2002.

# APPENDIX C

# DETAILED ECONOMIC ANALYSIS

| Snook's Arm Penstock Replacement<br>Comparison of Alternatives | | |
|---|---|---|
| **Base Case** | **CPW Preference against Plant Retirement Alternative<br>CPW (2004$)** | **Payback Period** |
| Full Replacement in 2006 | $585,923 | 13 years |
| Phased in Replacement (2006 and 2016) | $577,488 | 7 & 13 years |
| **Sensitivy Case - Emissions Credits** | | |
| Full Replacement in 2006 | $862,672 | 10 years |
| Phased in Replacement (2006 and 2016) | $854,237 | 6 & 11 years |



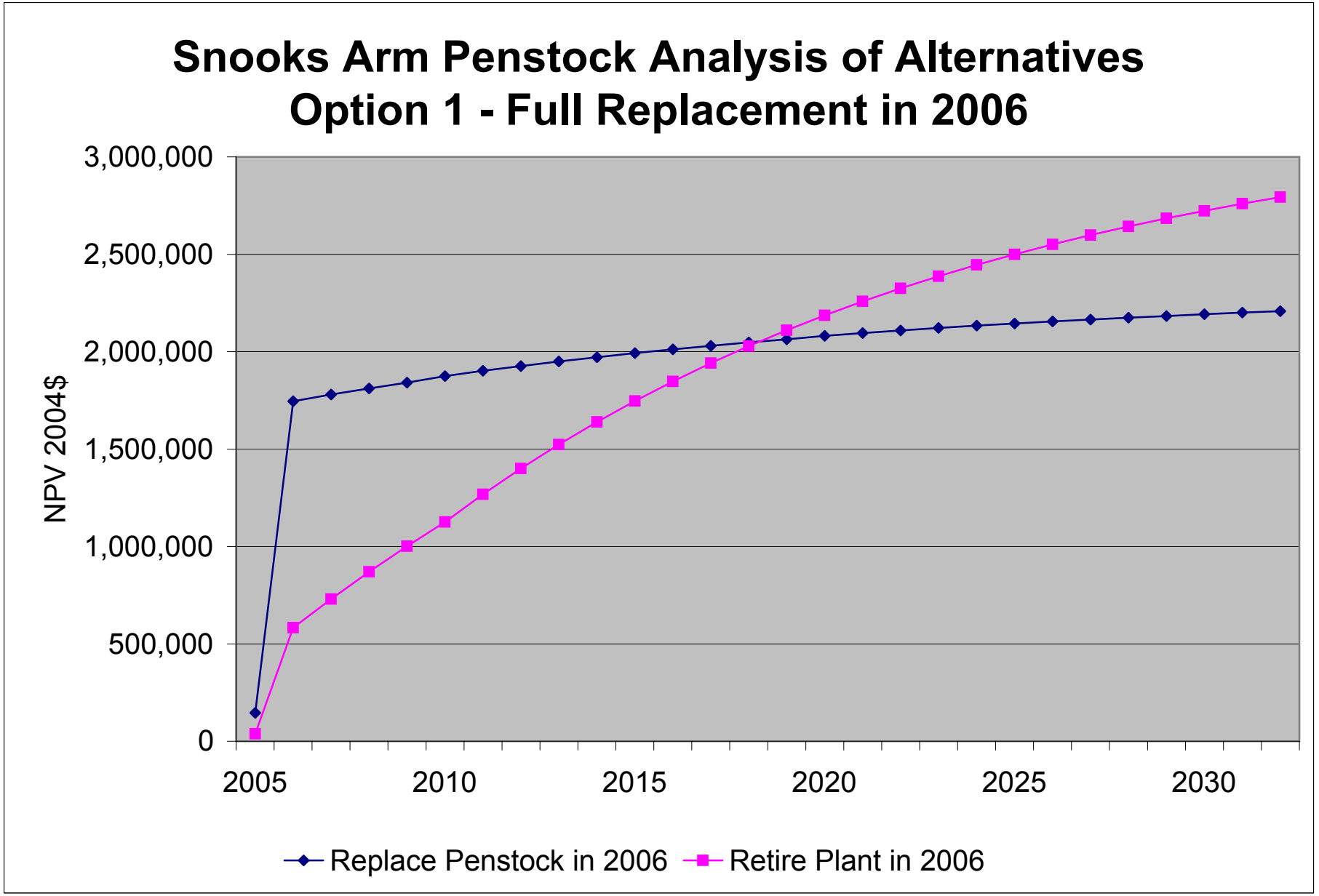



# Snooks Arm Penstock Replacement

**Option 1 - Full Replacement in 2005/6**

| Assumptions | | | | |
|---|---|---|---|---|
| Annual Escalation: | 2.0% | | Engineering (2005): | 112,000 |
| Discount Rate: | 8.5% | | Construction (2006): | 1,735,000 |
| Installed Capacity: | 590 | kW | | |
| Annual Energy: | 3,500,000 | kWh | | |
| Holyrood Conversion: | 624 | kWH/BBL | Operator + O&M (2003$): | 40,000 |
| Holyrood Var O&M: | 4.5 | mills/kWh 2004$ | Runner Maintenance (2003$): | 7,500 |
| Fuel Forecast: | Fall 2002 | mills/kWh | Upper Penstock Maintenance (2003$) | 20,000 |
| Capacity Value (CT equiv.): | 100 | $/kW/yr 2004$ | Retire Plant in 2006: | 500,000 |

| | Replace Penstock in 2006 | | | | | Retire Plant in 2006 | | | | | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capital Cost | Plant O&M | Runner & Penstock Maint. | Sub-total Current$ | Sub-total CPW 2004$ | Capital Cost | Operator | Capacity | Holyrood Var O&M | Holyrood Fuel | Sub-total Current$ | Sub-total CPW 2004$ | TOTAL Current$ | TOTAL CPW 2004$ |
| 2004 | | | | | | | | | | | | | | |
| 2005 | 116,525 | 41,616 | | 158,141 | 145,752 | | 41,616 | | | | 41,616 | 38,356 | 116,525 | 107,396 |
| 2006 | 1,841,196 | 42,448 | | 1,883,644 | 1,745,823 | 530,604 | 21,224 | | 8,193 | 81,190 | 641,211 | 583,036 | 1,242,433 | 1,162,787 |
| 2007 | | 43,297 | | 43,297 | 1,779,721 | | | | 16,714 | 170,513 | 187,227 | 729,617 | -143,930 | 1,050,104 |
| 2008 | | 44,163 | | 44,163 | 1,811,588 | | | | 17,048 | 176,402 | 193,451 | 869,206 | -149,287 | 942,382 |
| 2009 | | 45,046 | | 45,046 | 1,841,546 | | | | 17,389 | 181,731 | 199,120 | 1,001,630 | -154,074 | 839,916 |
| 2010 | | 45,947 | 8,615 | 54,563 | 1,874,990 | | | | 17,737 | 184,535 | 202,272 | 1,125,612 | -147,710 | 749,378 |
| 2011 | | 46,866 | | 46,866 | 1,901,466 | | | 45,895 | 18,092 | 187,340 | 251,327 | 1,267,593 | -204,460 | 633,873 |
| 2012 | | 47,804 | | 47,804 | 1,926,356 | | | 45,895 | 18,454 | 190,144 | 254,493 | 1,400,100 | -206,689 | 526,256 |
| 2013 | | 48,760 | | 48,760 | 1,949,755 | | | 45,895 | 18,823 | 192,949 | 257,666 | 1,523,749 | -208,907 | 426,006 |
| 2014 | | 49,735 | | 49,735 | 1,971,752 | | | 45,895 | 19,199 | 195,753 | 260,847 | 1,639,118 | -211,112 | 332,634 |
| 2015 | | 50,730 | | 50,730 | 1,992,431 | | | 45,895 | 19,583 | 198,558 | 264,036 | 1,746,748 | -213,306 | 245,683 |
| 2016 | | 51,744 | | 51,744 | 2,011,872 | | | 45,895 | 19,975 | 201,643 | 267,512 | 1,847,253 | -215,768 | 164,619 |
| 2017 | | 52,779 | | 52,779 | 2,030,147 | | | 45,895 | 20,374 | 204,728 | 270,997 | 1,941,091 | -218,218 | 89,057 |
| 2018 | | 53,835 | | 53,835 | 2,047,328 | | | 45,895 | 20,782 | 207,813 | 274,489 | 2,028,692 | -220,655 | 18,637 |
| 2019 | | 54,911 | | 54,911 | 2,063,480 | | | 45,895 | 21,197 | 210,897 | 277,990 | 2,110,460 | -223,078 | -46,980 |
| 2020 | | 56,010 | 10,502 | 66,511 | 2,081,511 | | | 45,895 | 21,621 | 213,982 | 281,499 | 2,186,773 | -214,987 | -105,262 |
| 2021 | | 57,130 | | 57,130 | 2,095,785 | | | 45,895 | 22,054 | 217,348 | 285,297 | 2,258,057 | -228,167 | -162,271 |
| 2022 | | 58,272 | | 58,272 | 2,109,205 | | | 45,895 | 22,495 | 220,994 | 289,383 | 2,324,697 | -231,111 | -215,493 |
| 2023 | | 59,438 | | 59,438 | 2,121,820 | | | 45,895 | 22,945 | 224,639 | 293,479 | 2,386,986 | -234,041 | -265,167 |
| 2024 | | 60,627 | | 60,627 | 2,133,679 | | | 45,895 | 23,404 | 228,566 | 297,864 | 2,445,254 | -237,238 | -311,574 |
| 2025 | | 61,839 | | 61,839 | 2,144,829 | | | 45,895 | 23,872 | 232,212 | 301,978 | 2,499,698 | -240,139 | -354,869 |
| 2026 | | 63,076 | | 63,076 | 2,155,310 | | | 45,895 | 24,349 | 236,138 | 306,382 | 2,550,608 | -243,306 | -395,299 |
| 2027 | | 64,337 | | 64,337 | 2,165,163 | | | 45,895 | 24,836 | 240,064 | 310,795 | 2,598,207 | -246,458 | -433,044 |
| 2028 | | 65,624 | | 65,624 | 2,174,426 | | | 45,895 | 25,333 | 243,990 | 315,218 | 2,642,700 | -249,594 | -468,274 |
| 2029 | | 66,937 | | 66,937 | 2,183,134 | | | 45,895 | 25,840 | 248,197 | 319,932 | 2,684,321 | -252,995 | -501,187 |
| 2030 | | 68,275 | 12,802 | 81,077 | 2,192,855 | | | 45,895 | 26,356 | 252,404 | 324,655 | 2,723,248 | -243,578 | -530,393 |
| 2031 | | 69,641 | | 69,641 | 2,200,551 | | | 45,895 | 26,883 | 256,611 | 329,389 | 2,759,649 | -259,748 | -559,097 |
| 2032 | | 71,034 | | 71,034 | 2,207,786 | | | 45,895 | 27,421 | 261,098 | 334,414 | 2,793,709 | -263,380 | -585,923 |

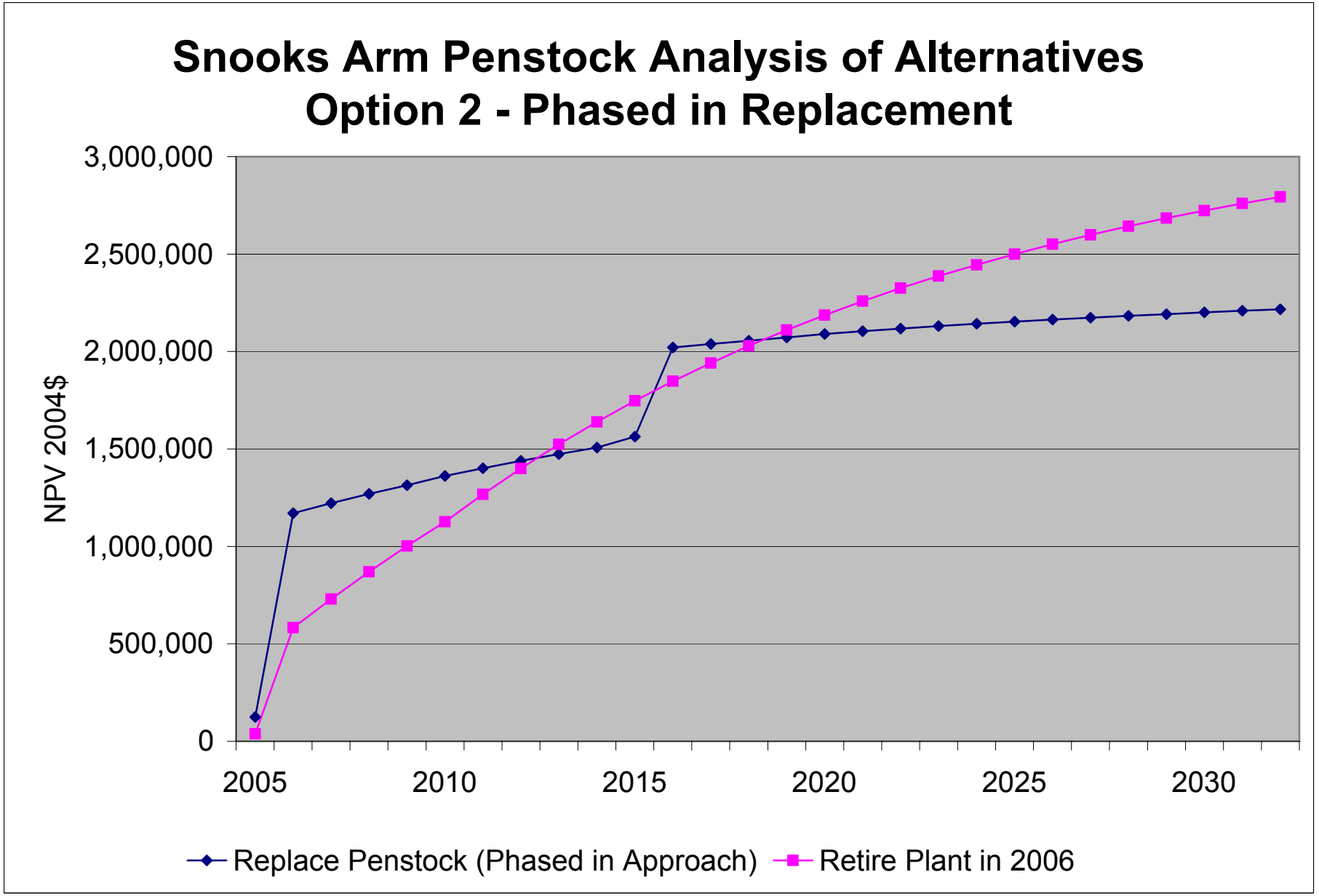

Snooks Arm Penstock Analysis of Alternatives
Option 1 - Full Replacement in 2006
NPV 2004$
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock in 2006
Retire Plant in 2006

# Snooks Arm Penstock Replacement

**Option 2 - Phased in Replacement**

| Assumptions | | | | |
|---|---|---|---|---|
| Annual Escalation: | 2.0% | | Engineering - High Pressure Section (2005): | 90,000 |
| Discount Rate: | 8.5% | | Construction - High Pressure Section (2006): | 1,100,000 |
| Installed Capacity: | 590 | kW | Engineering - Low Pressure Section (2015): | 50,000 |
| Annual Energy: | 3,500,000 | kWh | Construction - Low Pressure Section (2016): | 900,000 |
| Holyrood Conversion: | 624 | kWH/BBL | Operator + O&M (2003$): | 40,000 |
| Holyrood Var O&M: | 4.5 | mills/kWh 2004$ | Runner Maintenance (2003$): | 7,500 |
| Fuel Forecast: | Fall 2002 | mills/kWh | Upper Penstock Maintenance (2003$) | 20,000 |
| Capacity Value (CT equiv.): | 100 | $/kW/yr 2004$ | Retire Plant in 2006: | 500,000 |

| | Replace Penstock (Phased in Approach) | | | | | Retire Plant in 2006 | | | | | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capital Cost | Plant O&M | Runner & Penstock Maint. | Sub-total Current$ | Sub-total CPW 2004$ | Capital Cost | Operator | Capacity | Holyrood Var O&M | Holyrood Fuel | Sub-total Current$ | Sub-total CPW 2004$ | TOTAL Current$ | TOTAL CPW 2004$ |
| 2004 | | | | | | | | | | | | | | |
| 2005 | 93,636 | 41,616 | | 135,252 | 124,656 | | 41,616 | | | | 41,616 | 38,356 | 93,636 | 86,300 |
| 2006 | 1,167,329 | 42,448 | 21,224 | 1,231,001 | 1,170,337 | 530,604 | 21,224 | | 8,193 | 81,190 | 641,211 | 583,036 | 589,790 | 587,301 |
| 2007 | | 43,297 | 21,649 | 64,946 | 1,221,183 | | | | 16,714 | 170,513 | 187,227 | 729,617 | -122,281 | 491,566 |
| 2008 | | 44,163 | 22,082 | 66,245 | 1,268,984 | | | | 17,048 | 176,402 | 193,451 | 869,206 | -127,206 | 399,778 |
| 2009 | | 45,046 | 22,523 | 67,570 | 1,313,921 | | | | 17,389 | 181,731 | 199,120 | 1,001,630 | -131,550 | 312,291 |
| 2010 | | 45,947 | 31,589 | 77,536 | 1,361,446 | | | | 17,737 | 184,535 | 202,272 | 1,125,612 | -124,736 | 235,834 |
| 2011 | | 46,866 | 23,433 | 70,300 | 1,401,161 | | | 45,895 | 18,092 | 187,340 | 251,327 | 1,267,593 | -181,027 | 133,568 |
| 2012 | | 47,804 | 23,902 | 71,706 | 1,438,495 | | | 45,895 | 18,454 | 190,144 | 254,493 | 1,400,100 | -182,787 | 38,396 |
| 2013 | | 48,760 | 24,380 | 73,140 | 1,473,594 | | | 45,895 | 18,823 | 192,949 | 257,666 | 1,523,749 | -184,527 | -50,155 |
| 2014 | | 49,735 | 24,867 | 74,602 | 1,506,589 | | | 45,895 | 19,199 | 195,753 | 260,847 | 1,639,118 | -186,245 | -132,528 |
| 2015 | 63,412 | 50,730 | 25,365 | 139,507 | 1,563,457 | | | 45,895 | 19,583 | 198,558 | 264,036 | 1,746,748 | -124,529 | -183,291 |
| 2016 | 1,164,246 | 51,744 | | 1,215,990 | 2,020,307 | | | 45,895 | 19,975 | 201,643 | 267,512 | 1,847,253 | 948,478 | 173,054 |
| 2017 | | 52,779 | | 52,779 | 2,038,583 | | | 45,895 | 20,374 | 204,728 | 270,997 | 1,941,091 | -218,218 | 97,492 |
| 2018 | | 53,835 | | 53,835 | 2,055,763 | | | 45,895 | 20,782 | 207,813 | 274,489 | 2,028,692 | -220,655 | 27,072 |
| 2019 | | 54,911 | | 54,911 | 2,071,915 | | | 45,895 | 21,197 | 210,897 | 277,990 | 2,110,460 | -223,078 | -38,545 |
| 2020 | | 56,010 | 10,502 | 66,511 | 2,089,946 | | | 45,895 | 21,621 | 213,982 | 281,499 | 2,186,773 | -214,987 | -96,827 |
| 2021 | | 57,130 | | 57,130 | 2,104,221 | | | 45,895 | 22,054 | 217,348 | 285,297 | 2,258,057 | -228,167 | -153,836 |
| 2022 | | 58,272 | | 58,272 | 2,117,640 | | | 45,895 | 22,495 | 220,994 | 289,383 | 2,324,697 | -231,111 | -207,058 |
| 2023 | | 59,438 | | 59,438 | 2,130,255 | | | 45,895 | 22,945 | 224,639 | 293,479 | 2,386,986 | -234,041 | -256,731 |
| 2024 | | 60,627 | | 60,627 | 2,142,115 | | | 45,895 | 23,404 | 228,566 | 297,864 | 2,445,254 | -237,238 | -303,139 |
| 2025 | | 61,839 | | 61,839 | 2,153,264 | | | 45,895 | 23,872 | 232,212 | 301,978 | 2,499,698 | -240,139 | -346,434 |
| 2026 | | 63,076 | | 63,076 | 2,163,745 | | | 45,895 | 24,349 | 236,138 | 306,382 | 2,550,608 | -243,306 | -386,864 |
| 2027 | | 64,337 | | 64,337 | 2,173,598 | | | 45,895 | 24,836 | 240,064 | 310,795 | 2,598,207 | -246,458 | -424,608 |
| 2028 | | 65,624 | | 65,624 | 2,182,861 | | | 45,895 | 25,333 | 243,990 | 315,218 | 2,642,700 | -249,594 | -459,839 |
| 2029 | | 66,937 | | 66,937 | 2,191,569 | | | 45,895 | 25,840 | 248,197 | 319,932 | 2,684,321 | -252,995 | -492,752 |
| 2030 | | 68,275 | 12,802 | 81,077 | 2,201,291 | | | 45,895 | 26,356 | 252,404 | 324,655 | 2,723,248 | -243,578 | -521,958 |
| 2031 | | 69,641 | | 69,641 | 2,208,986 | | | 45,895 | 26,883 | 256,611 | 329,389 | 2,759,649 | -259,748 | -550,662 |
| 2032 | | 71,034 | | 71,034 | 2,216,221 | | | 45,895 | 27,421 | 261,098 | 334,414 | 2,793,709 | -263,380 | -577,488 |


Snooks Arm Penstock Analysis of Alternatives
Option 2 - Phased in Replacement
NPV 2004$
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock (Phased in Approach)
Retire Plant in 2006

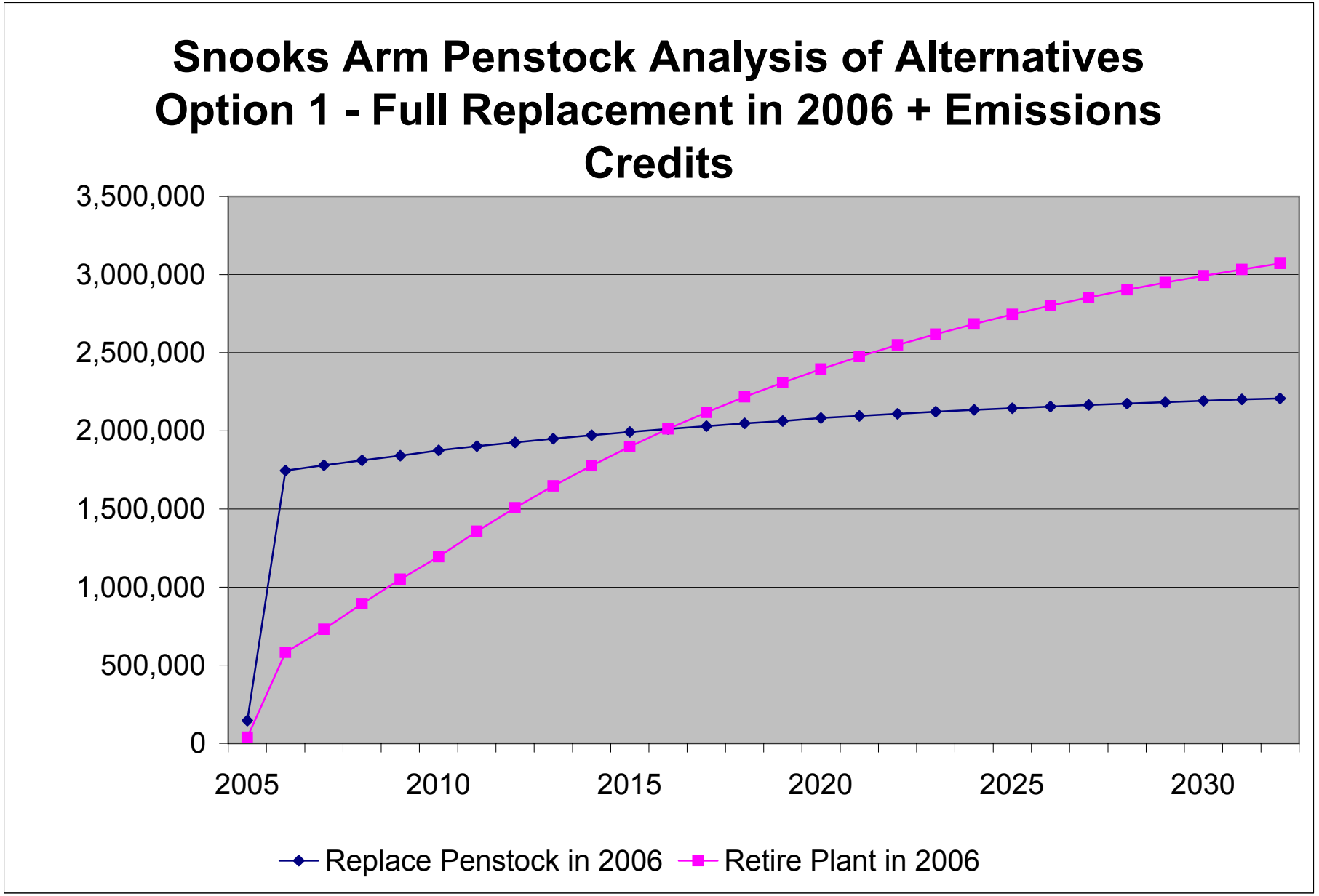
# Snooks Arm Penstock Replacement

**Option 1 - Full Replacement in 2005/6 + Emissions Credits**

| Assumptions | | | | |
|---|---|---|---|---|
| Annual Escalation: | 2.0% | | Engineering (2005): | 112,000 |
| Discount Rate: | 8.5% | | Construction (2006): | 1,735,000 |
| Installed Capacity: | 590 | kW | | |
| Annual Energy: | 3,500,000 | kWh | | |
| Holyrood Conversion: | 624 | kWH/BBL | Operator + O&M (2003$): | 40,000 |
| Holyrood Var O&M: | 4.5 | mills/kWh 2004$ | Runner Maintenance (2003$): | 7,500 |
| Fuel Forecast: | Fall 2002 | mills/kWh | Upper Penstock Maintenance (2003$) | 20,000 |
| Capacity Value (CT equiv.): | 100 | $/kW/yr 2004$ | Retire Plant in 2006: | 500,000 |

| | Replace Penstock in 2006 | | | | | Retire Plant in 2006 | | | | | | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capital Cost | Plant O&M | Runner & Penstock Maint. | Sub-total Current$ | Sub-total CPW 2004$ | Capital Cost | Operator | Capacity | $CO_2$ & $SO_2$ Emissions** | Holyrood Var O&M | Holyrood Fuel | Sub-total Current$ | Sub-total CPW 2004$ | TOTAL Current$ | TOTAL CPW 2004$ |
| 2004 | | | | | | | | | | | | | | | |
| 2005 | 116,525 | 41,616 | | 158,141 | 145,752 | | 41,616 | | | | | 41,616 | 38,356 | 116,525 | 107,396 |
| 2006 | 1,841,196 | 42,448 | | 1,883,644 | 1,745,823 | 530,604 | 21,224 | | | 8,193 | 81,190 | 641,211 | 583,036 | 1,242,433 | 1,162,787 |
| 2007 | | 43,297 | | 43,297 | 1,779,721 | | | | | 16,714 | 170,513 | 187,227 | 729,617 | -143,930 | 1,050,104 |
| 2008 | | 44,163 | | 44,163 | 1,811,588 | | | | 34,540 | 17,048 | 176,402 | 227,991 | 894,130 | -183,827 | 917,459 |
| 2009 | | 45,046 | | 45,046 | 1,841,546 | | | | 34,540 | 17,389 | 181,731 | 233,660 | 1,049,524 | -188,614 | 792,022 |
| 2010 | | 45,947 | 8,615 | 54,563 | 1,874,990 | | | | 34,540 | 17,737 | 184,535 | 236,812 | 1,194,677 | -182,250 | 680,313 |
| 2011 | | 46,866 | | 46,866 | 1,901,466 | | | 45,895 | 34,540 | 18,092 | 187,340 | 285,867 | 1,356,171 | -239,000 | 545,296 |
| 2012 | | 47,804 | | 47,804 | 1,926,356 | | | 45,895 | 34,540 | 18,454 | 190,144 | 289,033 | 1,506,661 | -241,229 | 419,695 |
| 2013 | | 48,760 | | 48,760 | 1,949,755 | | | 45,895 | 34,540 | 18,823 | 192,949 | 292,206 | 1,646,885 | -243,447 | 302,870 |
| 2014 | | 49,735 | | 49,735 | 1,971,752 | | | 45,895 | 34,540 | 19,199 | 195,753 | 295,387 | 1,777,531 | -245,652 | 194,221 |
| 2015 | | 50,730 | | 50,730 | 1,992,431 | | | 45,895 | 34,540 | 19,583 | 198,558 | 298,576 | 1,899,241 | -247,846 | 93,190 |
| 2016 | | 51,744 | | 51,744 | 2,011,872 | | | 45,895 | 34,540 | 19,975 | 201,643 | 302,052 | 2,012,723 | -250,308 | -851 |
| 2017 | | 52,779 | | 52,779 | 2,030,147 | | | 45,895 | 34,540 | 20,374 | 204,728 | 305,537 | 2,118,520 | -252,758 | -88,373 |
| 2018 | | 53,835 | | 53,835 | 2,047,328 | | | 45,895 | 34,540 | 20,782 | 207,813 | 309,029 | 2,217,145 | -255,195 | -169,816 |
| 2019 | | 54,911 | | 54,911 | 2,063,480 | | | 45,895 | 34,540 | 21,197 | 210,897 | 312,530 | 2,309,072 | -257,618 | -245,592 |
| 2020 | | 56,010 | 10,502 | 66,511 | 2,081,511 | | | 45,895 | 34,540 | 21,621 | 213,982 | 316,039 | 2,394,749 | -249,527 | -313,238 |
| 2021 | | 57,130 | | 57,130 | 2,095,785 | | | 45,895 | 34,540 | 22,054 | 217,348 | 319,837 | 2,474,663 | -262,707 | -378,878 |
| 2022 | | 58,272 | | 58,272 | 2,109,205 | | | 45,895 | 34,540 | 22,495 | 220,994 | 323,923 | 2,549,258 | -265,651 | -440,053 |
| 2023 | | 59,438 | | 59,438 | 2,121,820 | | | 45,895 | 34,540 | 22,945 | 224,639 | 328,019 | 2,618,878 | -268,581 | -497,058 |
| 2024 | | 60,627 | | 60,627 | 2,133,679 | | | 45,895 | 34,540 | 23,404 | 228,566 | 332,404 | 2,683,901 | -271,778 | -550,222 |
| 2025 | | 61,839 | | 61,839 | 2,144,829 | | | 45,895 | 34,540 | 23,872 | 232,212 | 336,518 | 2,744,573 | -274,679 | -599,744 |
| 2026 | | 63,076 | | 63,076 | 2,155,310 | | | 45,895 | 34,540 | 24,349 | 236,138 | 340,922 | 2,801,223 | -277,846 | -645,913 |
| 2027 | | 64,337 | | 64,337 | 2,165,163 | | | 45,895 | 34,540 | 24,836 | 240,064 | 345,335 | 2,854,111 | -280,998 | -688,948 |
| 2028 | | 65,624 | | 65,624 | 2,174,426 | | | 45,895 | 34,540 | 25,333 | 243,990 | 349,758 | 2,903,480 | -284,134 | -729,054 |
| 2029 | | 66,937 | | 66,937 | 2,183,134 | | | 45,895 | 34,540 | 25,840 | 248,197 | 354,472 | 2,949,594 | -287,535 | -766,460 |
| 2030 | | 68,275 | 12,802 | 81,077 | 2,192,855 | | | 45,895 | 34,540 | 26,356 | 252,404 | 359,195 | 2,992,663 | -278,118 | -799,807 |
| 2031 | | 69,641 | | 69,641 | 2,200,551 | | | 45,895 | 34,540 | 26,883 | 256,611 | 363,929 | 3,032,880 | -294,288 | -832,329 |
| 2032 | | 71,034 | | 71,034 | 2,207,786 | | | 45,895 | 34,540 | 27,421 | 261,098 | 368,954 | 3,070,459 | -297,920 | -862,672 |

** Assumes value associated with reduction of 2814 tonnes $CO_2$ @ $10/tonne and 32 tonnes $SO_2$ @ $200/tonne annually


Snooks Arm Penstock Analysis of Alternatives
Option 1 - Full Replacement in 2006 + Emissions Credits
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock in 2006
Retire Plant in 2006

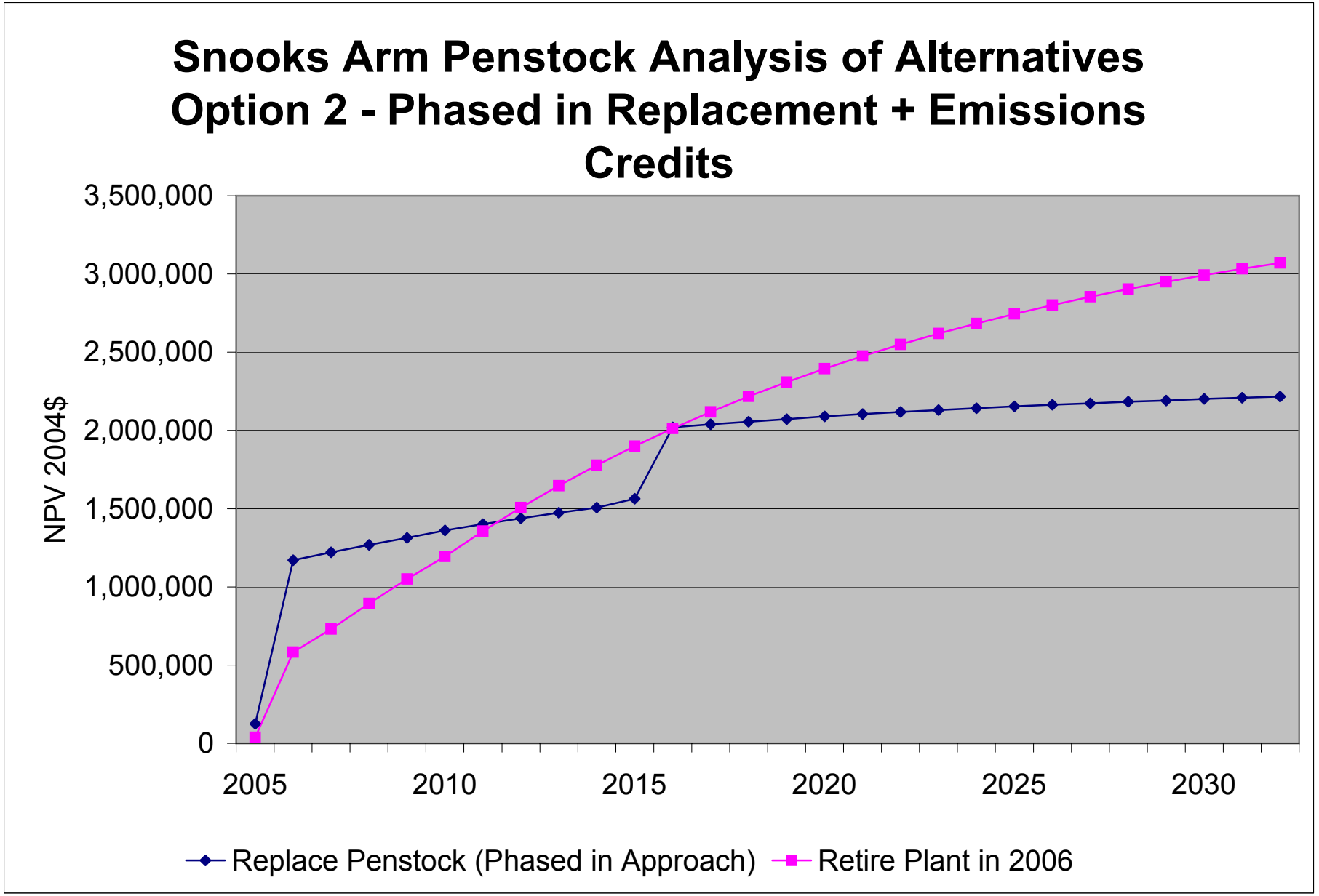
# Snooks Arm Penstock Replacement

**Option 2 - Phased in Replacement + Emissions Credits**

| Assumptions | | | | |
|---|---|---|---|---|
| Annual Escalation: | 2.0% | | Engineering - High Pressure Section (2005): | 90,000 |
| Discount Rate: | 8.5% | | Construction - High Pressure Section (2006): | 1,100,000 |
| Installed Capacity: | 590 | kW | Engineering - Low Pressure Section (2015): | 50,000 |
| Annual Energy: | 3,500,000 | kWh | Construction - Low Pressure Section (2016): | 900,000 |
| Holyrood Conversion: | 624 | kWH/BBL | Operator + O&M (2003$): | 40,000 |
| Holyrood Var O&M: | 4.5 | mills/kWh 2004$ | Runner Maintenance (2003$): | 7,500 |
| Fuel Forecast: | Fall 2002 | mills/kWh | Upper Penstock Maintenance (2003$) | 20,000 |
| Capacity Value (CT equiv.): | 100 | $/kW/yr 2004$ | Retire Plant in 2006: | 500,000 |

| | Replace Penstock (Phased in Approach) | | | | | Retire Plant in 2006 | | | | | | | | Difference | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capital Cost | Plant O&M | Runner & Penstock Maint. | Sub-total Current$ | Sub-total CPW 2004$ | Capital Cost | Operator | Capacity | $CO_2$ & $SO_2$ Emissions** | Holyrood Var O&M | Holyrood Fuel | Sub-total Current$ | Sub-total CPW 2004$ | TOTAL Current$ | TOTAL CPW 2004$ |
| 2004 | | | | | | | | | | | | | | | |
| 2005 | 93,636 | 41,616 | | 135,252 | 124,656 | | 41,616 | | | | | 41,616 | 38,356 | 93,636 | 86,300 |
| 2006 | 1,167,329 | 42,448 | 21,224 | 1,231,001 | 1,170,337 | 530,604 | 21,224 | | | 8,193 | 81,190 | 641,211 | 583,036 | 589,790 | 587,301 |
| 2007 | | 43,297 | 21,649 | 64,946 | 1,221,183 | | | | | 16,714 | 170,513 | 187,227 | 729,617 | -122,281 | 491,566 |
| 2008 | | 44,163 | 22,082 | 66,245 | 1,268,984 | | | | 34,540 | 17,048 | 176,402 | 227,991 | 894,130 | -161,746 | 374,854 |
| 2009 | | 45,046 | 22,523 | 67,570 | 1,313,921 | | | | 34,540 | 17,389 | 181,731 | 233,660 | 1,049,524 | -166,090 | 264,397 |
| 2010 | | 45,947 | 31,589 | 77,536 | 1,361,446 | | | | 34,540 | 17,737 | 184,535 | 236,812 | 1,194,677 | -159,276 | 166,769 |
| 2011 | | 46,866 | 23,433 | 70,300 | 1,401,161 | | | 45,895 | 34,540 | 18,092 | 187,340 | 285,867 | 1,356,171 | -215,567 | 44,990 |
| 2012 | | 47,804 | 23,902 | 71,706 | 1,438,495 | | | 45,895 | 34,540 | 18,454 | 190,144 | 289,033 | 1,506,661 | -217,327 | -68,166 |
| 2013 | | 48,760 | 24,380 | 73,140 | 1,473,594 | | | 45,895 | 34,540 | 18,823 | 192,949 | 292,206 | 1,646,885 | -219,067 | -173,291 |
| 2014 | | 49,735 | 24,867 | 74,602 | 1,506,589 | | | 45,895 | 34,540 | 19,199 | 195,753 | 295,387 | 1,777,531 | -220,785 | -270,941 |
| 2015 | 63,412 | 50,730 | 25,365 | 139,507 | 1,563,457 | | | 45,895 | 34,540 | 19,583 | 198,558 | 298,576 | 1,899,241 | -159,069 | -335,784 |
| 2016 | 1,164,246 | 51,744 | | 1,215,990 | 2,020,307 | | | 45,895 | 34,540 | 19,975 | 201,643 | 302,052 | 2,012,723 | 913,938 | 7,584 |
| 2017 | | 52,779 | | 52,779 | 2,038,583 | | | 45,895 | 34,540 | 20,374 | 204,728 | 305,537 | 2,118,520 | -252,758 | -79,938 |
| 2018 | | 53,835 | | 53,835 | 2,055,763 | | | 45,895 | 34,540 | 20,782 | 207,813 | 309,029 | 2,217,145 | -255,195 | -161,381 |
| 2019 | | 54,911 | | 54,911 | 2,071,915 | | | 45,895 | 34,540 | 21,197 | 210,897 | 312,530 | 2,309,072 | -257,618 | -237,157 |
| 2020 | | 56,010 | 10,502 | 66,511 | 2,089,946 | | | 45,895 | 34,540 | 21,621 | 213,982 | 316,039 | 2,394,749 | -249,527 | -304,803 |
| 2021 | | 57,130 | | 57,130 | 2,104,221 | | | 45,895 | 34,540 | 22,054 | 217,348 | 319,837 | 2,474,663 | -262,707 | -370,442 |
| 2022 | | 58,272 | | 58,272 | 2,117,640 | | | 45,895 | 34,540 | 22,495 | 220,994 | 323,923 | 2,549,258 | -265,651 | -431,618 |
| 2023 | | 59,438 | | 59,438 | 2,130,255 | | | 45,895 | 34,540 | 22,945 | 224,639 | 328,019 | 2,618,878 | -268,581 | -488,622 |
| 2024 | | 60,627 | | 60,627 | 2,142,115 | | | 45,895 | 34,540 | 23,404 | 228,566 | 332,404 | 2,683,901 | -271,778 | -541,787 |
| 2025 | | 61,839 | | 61,839 | 2,153,264 | | | 45,895 | 34,540 | 23,872 | 232,212 | 336,518 | 2,744,573 | -274,679 | -591,309 |
| 2026 | | 63,076 | | 63,076 | 2,163,745 | | | 45,895 | 34,540 | 24,349 | 236,138 | 340,922 | 2,801,223 | -277,846 | -637,478 |
| 2027 | | 64,337 | | 64,337 | 2,173,598 | | | 45,895 | 34,540 | 24,836 | 240,064 | 345,335 | 2,854,111 | -280,998 | -680,513 |
| 2028 | | 65,624 | | 65,624 | 2,182,861 | | | 45,895 | 34,540 | 25,333 | 243,990 | 349,758 | 2,903,480 | -284,134 | -720,619 |
| 2029 | | 66,937 | | 66,937 | 2,191,569 | | | 45,895 | 34,540 | 25,840 | 248,197 | 354,472 | 2,949,594 | -287,535 | -758,025 |
| 2030 | | 68,275 | 12,802 | 81,077 | 2,201,291 | | | 45,895 | 34,540 | 26,356 | 252,404 | 359,195 | 2,992,663 | -278,118 | -791,372 |
| 2031 | | 69,641 | | 69,641 | 2,208,986 | | | 45,895 | 34,540 | 26,883 | 256,611 | 363,929 | 3,032,880 | -294,288 | -823,894 |
| 2032 | | 71,034 | | 71,034 | 2,216,221 | | | 45,895 | 34,540 | 27,421 | 261,098 | 368,954 | 3,070,459 | -297,920 | -854,237 |

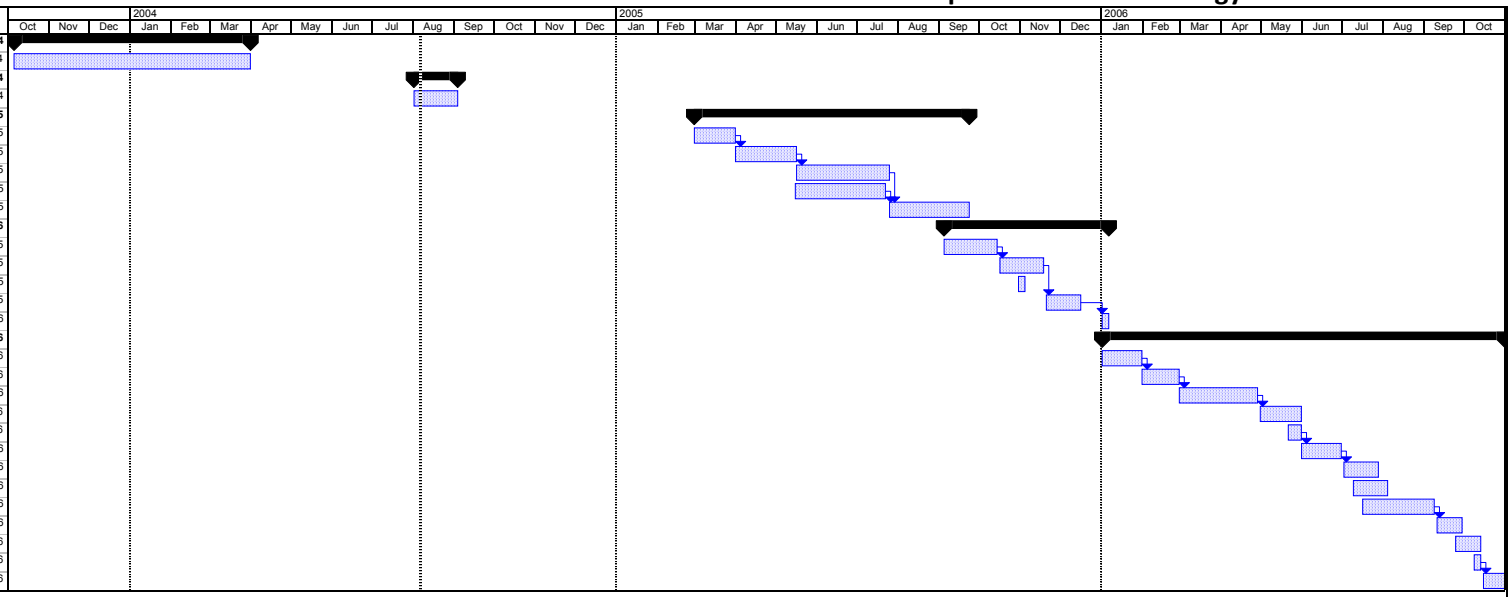
** Assumes value associated with reduction of 2814 tonnes $CO_2$ @ $10/tonne and 32 tonnes $SO_2$ @ $200/tonne annually


Snooks Arm Penstock Analysis of Alternatives
Option 2 - Phased in Replacement + Emissions Credits
NPV 2004$
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
2005
2010
2015
2020
2025
2030
Replace Penstock (Phased in Approach)
Retire Plant in 2006

# APPENDIX D

# PROJECT SCHEDULE

| ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|
| 1 | **Project Review** | **128 days** | **Mon 10/6/03** | **Wed 3/31/04** |
| 2 | CBP Review | 128 days | Mon 10/6/03 | Wed 3/31/04 |
| 3 | **PUB** | **25 days** | **Mon 8/2/04** | **Fri 9/3/04** |
| 4 | PUB Approval | 25 days | Mon 8/2/04 | Fri 9/3/04 |
| 5 | **Pre-Construction** | **149 days** | **Tue 3/1/05** | **Fri 9/23/05** |
| 6 | RFP Engineering Services | 23 days | Tue 3/1/05 | Thu 3/31/05 |
| 7 | Field Data | 32 days | Fri 4/1/05 | Mon 5/16/05 |
| 8 | Options & Recommend. | 50 days | Tue 5/17/05 | Mon 7/25/05 |
| 9 | Project Logic | 50 days | Mon 5/16/05 | Fri 7/22/05 |
| 10 | Design & Spec | 44 days | Tue 7/26/05 | Fri 9/23/05 |
| 11 | **Tender** | **90 days** | **Mon 9/5/05** | **Fri 1/6/06** |
| 12 | Prepare Tender | 30 days | Mon 9/5/05 | Fri 10/14/05 |
| 13 | Issue Tender | 25 days | Mon 10/17/05 | Fri 11/18/05 |
| 14 | Site Visit | 5 days | Mon 10/31/05 | Fri 11/4/05 |
| 15 | Evaluation | 20 days | Mon 11/21/05 | Fri 12/16/05 |
| 16 | Contract Award | 5 days | Mon 1/2/06 | Fri 1/6/06 |
| 17 | **Construction** | **217 days** | **Mon 1/2/06** | **Tue 10/31/06** |
| 18 | Documentation | 22 days | Mon 1/2/06 | Tue 1/31/06 |
| 19 | Shop Drawings | 20 days | Wed 2/1/06 | Tue 2/28/06 |
| 20 | Fabrication | 43 days | Wed 3/1/06 | Fri 4/28/06 |
| 21 | Delivery | 23 days | Mon 5/1/06 | Wed 5/31/06 |
| 22 | Mobilization | 8 days | Mon 5/22/06 | Wed 5/31/06 |
| 23 | Removals | 22 days | Thu 6/1/06 | Fri 6/30/06 |
| 24 | Site Preparation | 20 days | Mon 7/3/06 | Fri 7/28/06 |
| 25 | Road / Brook Crossings | 20 days | Mon 7/10/06 | Fri 8/4/06 |
| 26 | Installation | 40 days | Mon 7/17/06 | Fri 9/8/06 |
| 27 | Commissioning | 15 days | Mon 9/11/06 | Fri 9/29/06 |
| 28 | Clean-up | 15 days | Mon 9/25/06 | Fri 10/13/06 |
| 29 | Demobilization | 5 days | Mon 10/9/06 | Fri 10/13/06 |
| 30 | Contract Completion | 12 days | Mon 10/16/06 | Tue 10/31/06 |




Project: SA Penstock Schedule
Date: Fri 8/6/04

Task | Progress | Summary | Rolled Up Split | Rolled Up Progress | Project Summary | Deadline
Split | Milestone | Rolled Up Task | Rolled Up Milestone | External Tasks | External Milestone

# Newfoundland and Labrador Hydro

## Report Addendum

## Snook's Arm Wood Stave Penstock

## Update of Economic Analysis

**July 14, 2005**

## Introduction

As part of its 2005 Capital Budget, Hydro submitted and the Board approved a proposal to "Replace Penstock – Snook's Arm Generation Station". Final engineering commenced in 2005 with the bulk of the construction activities planned for completion in 2006. Due to a worldwide increase in the price of steel, the overall project estimate has increased from $1.93 million to $2.11 million. The following presents an update to the analysis of the economic viability of the proposed project.

## Summary

In addition to the increase in the estimated capital cost of the project, a number of other analysis inputs have also changed since the original report was filed with the Board in 2004. All changes are summarized below:

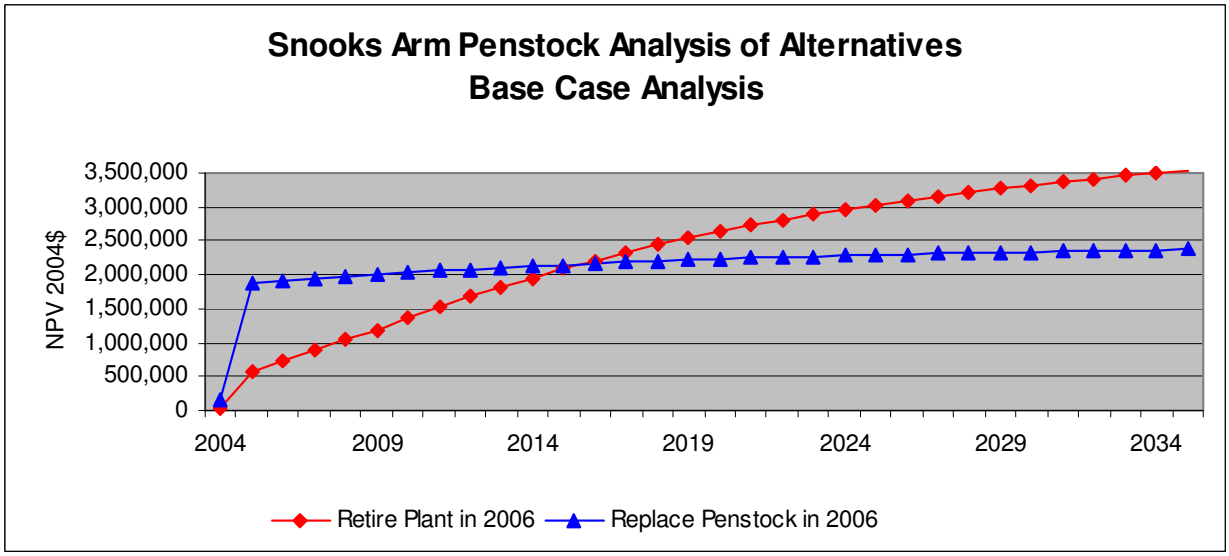
- Capital cost changed to $2,110,000
- Holyrood conversion efficiency changed to 630 kWh/bbl
- Holyrood variable O&M has been changed to 1.16 mills/kWh (2004$); and
- Forecast of fuel prices at Holyrood have been updated to reflect Hydro's latest estimates.

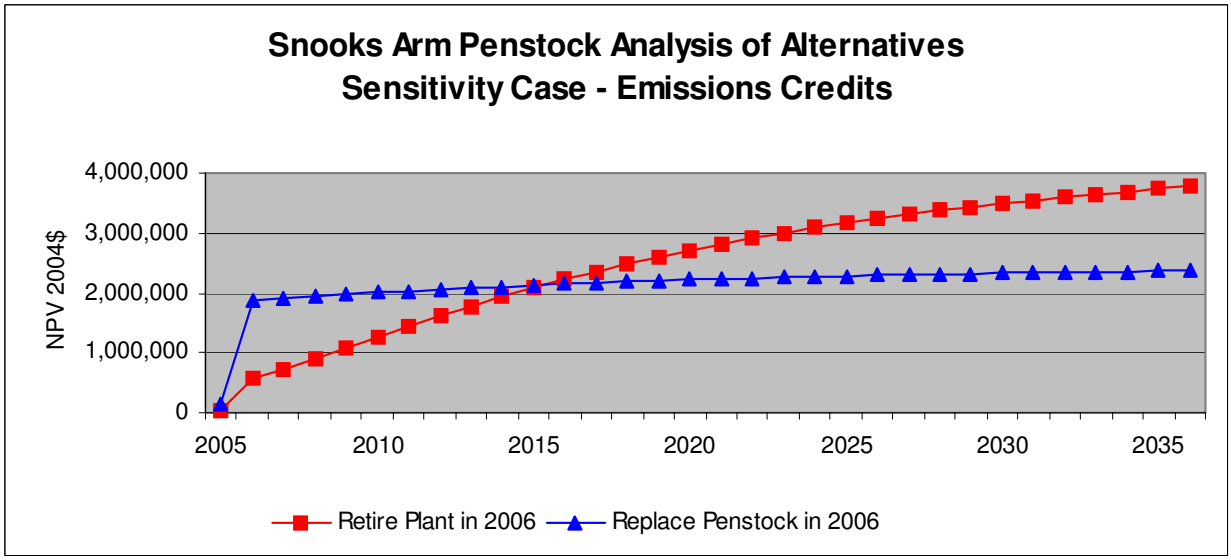
A summary of the detailed economic analysis (attached) is presented in the following table and graphs. Note that while the capital cost has increased, there has been a significant increase in the value of avoided fuel at Holyrood that has the overall effect of increasing the economic viability of the penstock replacement project.

Retire Plant in 2006



| Snook's Arm Penstock Replacement<br>Comparison of Alternatives | | |
|---|---|---|
| | CPW Preference Against Plant Retirement Alternative | |
| | CPW (2004$) | Payback Period |
| Base Case:<br>Full Replacement in 2006 | $1,161,092 | 11 Years |
| Sensitivity Case – Emissions Costs:<br>Full Replacement in 2006 | $1,398,735 | 10 Years |



# Newfoundland and Labrador Hydro

## Construction of New Diesel Plant – St. Lewis

## New Diesel Plant versus St. Lewis – Port Hope Simpson Interconnection

## Economic Analysis

**System Planning**

**June 2005**

## Introduction

An alternative to the construction of a new diesel plant at St. Lewis is to expend $3,400,000 to interconnect the St. Lewis Distribution System to the Port Hope Simpson Diesel Plant via a 50 km distribution line. This cost includes $400,000 for additional generation in the Port Hope Simpson Diesel Plant. This interconnection would enable the St. Lewis Diesel Plant to be shut down and taken out of service. An interconnection between St. Lewis and Mary's Harbour was also considered, but as the interconnection would be 6 km longer than from St. Lewis to Port Hope Simpson, the capital cost would be proportionately higher so it was decided to complete that analysis only if the St. Lewis – Port Hope Simpson interconnection showed promise.

One important consideration to note is that this is an interconnection of one diesel system to another and power will still be supplied by diesel generators of similar size. Primarily, the impact of reducing long-term fixed costs is being analyzed, as the interconnection will not lead to significant change in the cost of energy production, which is proportional to fuel cost and usage.

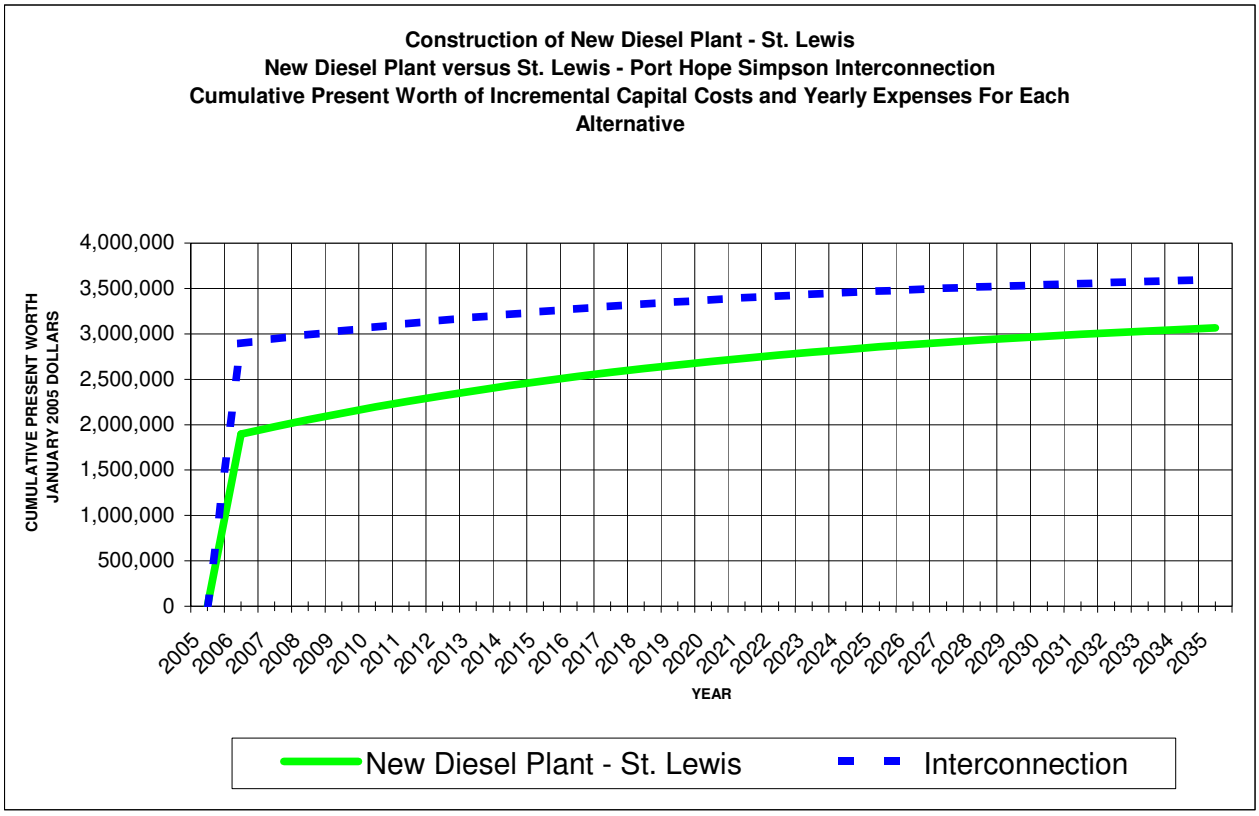
## Summary

This study only looked at the incremental costs between the two alternatives:

- As both diesel plants are of similar size and production efficiency, fuel, lube and variable O&M costs were considered to be the same in both cases and therefore were not included;
- An increase in station service costs for the new Diesel Plant alternative was offset by the increase in distribution losses for the Interconnection alternative;
- There would be a savings in fixed O&M costs at the St. Lewis Diesel Plant, if the Interconnection was constructed and the St. Lewis Diesel Plant shut down.

A summary of the detailed economic analysis (attached) is presented in the following table and graph. Over a 30 year period, the new Diesel Plant alternative has a CPW preference of $530,732 and has a positive CPW from the beginning.

| New Diesel Plant - St. Lewis versus St. Lewis – Port Hope Simpson Interconnection Comparison of Alternatives | | |
|---|---|---|
| | CPW Preference of New Diesel Plant Alternative | |
| | CPW (2005$) | Payback Period |
| Base Case | $530,732 | Immediate |



## Construction of New Diesel Plant - St. Lewis
## Economic Analysis

**New Diesel Plant versus St. Lewis - Port Hope Simpson Interconnection**

| Year | New Diesel Plant Alternative | | | | St. Lewis - Port Hope Simpson Interconnection Alternative | | | | Net Value of New Diesel Plant Over Interconnection | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ANNUAL | CONSTRUCTION | TOTAL NEW DIESEL $ | | CONSTRUCTION | ANNUAL | TOTAL INTERCONNECTION $ | | | | |
| | Fixed O&M | New Diesel Plant | $ For Year | CPW Jan-05 | Dist. Line & New Unit for PHS | O&M Dist Line | $ For Year | CPW Jan-05 | Net $ For Year | Net CPW Jan-05 | CPW Jan-05 |
| 2005 | | | | 0 | | | | 0 | | | |
| 2006 | 0 | 2,226,500 | 2,226,500 | 1,894,803 | 3,400,000 | | 3,400,000 | 2,893,479 | 1,173,500 | 998,676 | 998,676 |
| 2007 | 104,142 | 0 | 104,142 | 1,976,563 | | 62,485 | 62,485 | 2,942,535 | (41,657) | (32,704) | 965,972 |
| 2008 | 106,225 | 0 | 106,225 | 2,053,495 | | 63,735 | 63,735 | 2,988,694 | (42,490) | (30,773) | 935,199 |
| 2009 | 108,562 | 0 | 108,562 | 2,126,027 | | 65,137 | 65,137 | 3,032,213 | (43,425) | (29,013) | 906,186 |
| 2010 | 110,950 | 0 | 110,950 | 2,194,411 | | 66,570 | 66,570 | 3,073,244 | (44,380) | (27,353) | 878,833 |
| 2011 | 113,391 | 0 | 113,391 | 2,258,883 | | 68,035 | 68,035 | 3,111,927 | (45,356) | (25,789) | 853,044 |
| 2012 | 115,886 | 0 | 115,886 | 2,319,668 | | 69,531 | 69,531 | 3,148,398 | (46,354) | (24,314) | 828,730 |
| 2013 | 118,493 | 0 | 118,493 | 2,377,004 | | 71,096 | 71,096 | 3,182,800 | (47,397) | (22,935) | 805,795 |
| 2014 | 121,041 | 0 | 121,041 | 2,431,035 | | 72,624 | 72,624 | 3,215,218 | (48,416) | (21,612) | 784,183 |
| 2015 | 123,583 | 0 | 123,583 | 2,481,925 | | 74,150 | 74,150 | 3,245,752 | (49,433) | (20,356) | 763,827 |
| 2016 | 126,400 | 0 | 126,400 | 2,529,942 | | 75,840 | 75,840 | 3,274,563 | (50,560) | (19,207) | 744,620 |
| 2017 | 129,282 | 0 | 129,282 | 2,575,249 | | 77,569 | 77,569 | 3,301,746 | (51,713) | (18,122) | 726,498 |
| 2018 | 132,230 | 0 | 132,230 | 2,617,997 | | 79,338 | 79,338 | 3,327,395 | (52,892) | (17,099) | 709,398 |
| 2019 | 135,245 | 0 | 135,245 | 2,658,332 | | 81,147 | 81,147 | 3,351,596 | (54,098) | (16,134) | 693,264 |
| 2020 | 138,328 | 0 | 138,328 | 2,696,389 | | 82,997 | 82,997 | 3,374,431 | (55,331) | (15,223) | 678,041 |
| 2021 | 141,385 | 0 | 141,385 | 2,732,274 | | 84,831 | 84,831 | 3,395,961 | (56,554) | (14,354) | 663,688 |
| 2022 | 144,510 | 0 | 144,510 | 2,766,109 | | 86,706 | 86,706 | 3,416,263 | (57,804) | (13,534) | 650,153 |
| 2023 | 147,703 | 0 | 147,703 | 2,798,012 | | 88,622 | 88,622 | 3,435,405 | (59,081) | (12,761) | 637,392 |
| 2024 | 150,968 | 0 | 150,968 | 2,828,094 | | 90,581 | 90,581 | 3,453,453 | (60,387) | (12,033) | 625,360 |
| 2025 | 154,304 | 0 | 154,304 | 2,856,457 | | 92,582 | 92,582 | 3,470,472 | (61,722) | (11,345) | 614,014 |
| 2026 | 157,714 | 0 | 157,714 | 2,883,201 | | 94,629 | 94,629 | 3,486,518 | (63,086) | (10,698) | 603,317 |
| 2027 | 161,200 | 0 | 161,200 | 2,908,418 | | 96,720 | 96,720 | 3,501,648 | (64,480) | (10,087) | 593,230 |
| 2028 | 164,762 | 0 | 164,762 | 2,932,195 | | 98,857 | 98,857 | 3,515,914 | (65,905) | (9,511) | 583,719 |
| 2029 | 168,403 | 0 | 168,403 | 2,954,614 | | 101,042 | 101,042 | 3,529,366 | (67,361) | (8,968) | 574,751 |
| 2030 | 172,125 | 0 | 172,125 | 2,975,753 | | 103,275 | 103,275 | 3,542,049 | (68,850) | (8,456) | 566,296 |
| 2031 | 175,929 | 0 | 175,929 | 2,995,685 | | 105,557 | 105,557 | 3,554,008 | (70,372) | (7,973) | 558,323 |
| 2032 | 179,817 | 0 | 179,817 | 3,014,479 | | 107,890 | 107,890 | 3,565,284 | (71,927) | (7,517) | 550,806 |
| 2033 | 183,791 | 0 | 183,791 | 3,032,199 | | 110,275 | 110,275 | 3,575,917 | (73,516) | (7,088) | 543,717 |
| 2034 | 187,853 | 0 | 187,853 | 3,048,908 | | 112,712 | 112,712 | 3,585,942 | (75,141) | (6,683) | 537,034 |
| 2035 | 192,004 | 0 | 192,004 | 3,064,662 | | 115,203 | 115,203 | 3,595,394 | (76,802) | (6,302) | 530,732 |
| CPW 2005$ | | | **3,064,662** | | | | **3,595,394** | | | | |

Discount Rate = 8.4%

| | |
|---|---|
| **CPW New Diesel Plant Cost - Jan 2005** | **3,064,662** |
| **CPW Interconnection Cost - Jan 2004** | **3,595,394** |
| **Cumulative Present Worth of New Diesel Plant** | **530,732** |