Q. **Reference: Reliability and Resource Adequacy Study 2022 Update, Volume III, page 25.**

Has there been any discussions or studies that address the impact to the reliability of the Holyrood units operating in off-design power levels? Provide a copy of any documentation of such discussion or study.

A. In 2019, Newfoundland and Labrador Hydro ("Hydro") engaged a consultant, Wood PLC ("Wood"), to provide a preliminary high-level view of lower minimum loads in their "2019 Holyrood Thermal Generating Station Condition Assessment Update Report."[1]

In this report, provided as PUB-NLH-277, Attachment 1, Wood stated its belief that minimum loads in the order of 30 to 40 MW per unit at the Holyrood Thermal Generating Station ("Holyrood TGS") should be achievable. Wood recommended the development and implementation of a test plan to establish the level and confidence of operation at lower loads, along with procedural changes and communication requirements to support such operation.

In 2020, Wood completed a follow up assessment, which included a series of tests performed on Holyrood TGS Unit 2, which showed that that minimum load of 30 MW is achievable. The report, "Assessment of Viability of Continued Operation of Holyrood Thermal Generating Station as a Backup Facility,"[2] provided as PUB-NLH-277, Attachment 2, documents this work.

Wood recommended further trials and optimizations to enable preparation of procedures for continued operation at low load. Operational changes, including control logic changes and boiler tuning at low loads, would be required to routinely operate at this load.

[1] "2019 Holyrood Thermal Generating Station Condition Assessment Update Report," Wood PLC, rev. June 16, 2020 (originally issued January 29, 2020).
[2] "Assessment of Viability of Continued Operation of Holyrood Thermal Generating Station as a Backup Facility," Wood PLC, rev. September 20, 2020 (originally issued on August 7, 2020).

In March 2021, low load testing was performed on Holyrood TGS Unit 3, which was successfully operated at 30 MW for several hours. This was documented in the "HTGS Condition Assessment and Life Extension Study."[3,4]

While low-load testing to date has been successful, the tests were completed for short operating periods—up to 15 hours. Hydro's boiler contractor, Babcock & Wilcox have stated that they do not recommend operation of the boilers below 30-40% of the units Maximum Continuous Rating (i.e., 50–70 MW) for extended periods of time.

Further engineering assessment and testing would be required to assess the viability and implications of continuous operation below 70 MW. Operation of boilers below the recommended minimum load level may also result in less efficient boiler operation, which could have implications regarding Hydro's emissions compliance.

[3] The "HTGS Condition Assessment and Life Extension Study," Hatch Ltd, March 30, 2022—including the Executive Summary, Volume I, and Volume II—were filed as attachments to the "Reliability and Resource Adequacy Study Review - Assessment to Determine the Potential Long-Term Viability of the Holyrood Thermal Generating Station," Newfoundland and Labrador Hydro, March 31, 2022.
[4] "HTGS Condition Assessment and Life Extension Study," Hatch Ltd, March 30, 2022, vol. II, sec. 4.6.

2019 HOLYROOD THERMAL GENERATING STATION CONDITION ASSESSMENT UPDATE REPORT

205882-0001-CD10-RPT-0001, Rev. 0

16 June 2020

Wood Canada Limited
PO Box 9600
133 Crosbie Road
St. John's, NL
A1A 3C1

REPORT

FOR

2019 HRD TGS CONDITION ASSESSMENT UPDATE REPORT

HOLYROOD THERMAL GENERATING STATION

FOR

NEWFOUNDLAND AND LABRADOR HYDRO

PROVINCE OF NEWFOUNDLAND AND LABRADOR
pegnl
ENGINEERING
PERMIT D0018
Wood Canada Limited
02827
Signature or Member Number
(Member-in-Responsible Charge)

REGISTERED PROFESSIONAL ENGINEER
BLAIR R. SECKINGTON
SIGNATURE
16-Jun-2020
DATE
NEWFOUNDLAND & LABRADOR

0	16 Jun 2020	Final Report, Rev 0	BS	RH	RH	JM
B	02 Mar 2020	90% ISSUED FOR Client Review & Comment	BS	LH	LH	JM
A	29 Jan 2020	50% ISSUED FOR Client Review & Comment	BS	LH	LH	JM
REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT

wood.	**2019 HRD TGS CONDITION ASSESSMENT UPDATE REPORT HOLYROOD THERMAL GENERATING STATION**	Wood Canada Limited Job No. 205882	
		REPORT **205882-0001-CD10-RPT-0001**	REV. 0

IMPORTANT NOTICE

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EXECUTIVE SUMMARY

Wood Canada Limited was contracted by Newfoundland and Labrador Hydro to prepare a "2019 Holyrood Condition Assessment Update study". The study objectives were as follows:

- Update the 2017 Condition Assessment Study for each of the three steam turbine generator units and common facilities at Holyrood TGS, focusing on major things that had changed since the 2017 study;
- Review the Holyrood Maintenance Programming;
- Review the Holyrood TGS capital plans, identifying additional items for consideration, particularly as it related to standby/emergency generation needs beyond the end of steam generation period;
- Review Human Resources/Staffing during the periods under consideration;
- Provide a preliminary high-level view of the potential opportunities for faster starts, particularly from a cold condition;
- Provide a preliminary high-level view of potential opportunities for quicker conversions of Unit 3 from generation to synchronous condensing and vice versa; and
- Provide a preliminary high level view of lower minimum loads.

The study was to look primarily at two periods:

- "Normal Mode Period" - from 2020 to March 31, 2023, where March 31, 2023 was the end of "normal steam generation mode" (as opposed to recent dates of March 31, 2021 or March 31, 2022. It was assumed that Units 1, 2, and 3 would continue to generate electricity at levels comparable to historical until March 31, 2023. Unit 3 would also continue to operate as a synchronous condenser to March 2023 and beyond to 2043 or thereabouts (extended from current March 31, 2021 NLH plans).

- "Standby/Emergency Generation Mode Period" – from end of "Normal Mode period" of March 31, 2023 to a "cold standby/emergency mode" end date likely sometime between March 2027 and March 2033. All three units would be in cold standby generation mode, with Unit 3 synchronous condensing operation continuing to 2043. Faster starts and Unit 3 conversions were key elements of this period; all three HRD units be able to start up within 12 to 24 hours and run at full load on all three units for two to four weeks.

Generally speaking the condition of the plant is good, Units 1, 2, and 3 are approximately 50, 49, and 40 years of age in 2019 respectively, however given their historical seasonal base load and lightly loaded service the operational age for the majority of the plant systems can be considered to be more like 30-25 years. They are thus past conventional calendar benchmarks for financial (often technical) end of life of 40 years. The units also have passed or are close to 200,000 hours of operation, which is another benchmark for potential technical end of life.

The boilers undergo regular boiler regulatory and condition assessment/repair inspections/overhauls. Many issues have been found since the major 2010 assessment, and repaired. Based on the history of many years of boiler inspection and repair, there is no reason why the plant boilers cannot continue, with appropriate inspections and repair work, to generate electricity reliably to March 2023 and in cold standby/emergency mode to 2027+.

Units 1 and 2 have had major generator inspections and testing that have indicated that these units are good to reach March 2021 (and by our assessment to March 2023) without any further rewinds. No testing indications suggest that they cannot likely achieve normal operation to 2023, and in cold standby/emergency operations to 2027+. Unit 3 was overhauled in 2016 and had its rotor rewound. Unit 3 is also planned to have a stator rewind in 2020 or 2021 for long term reliability purposes as a condensing unit. The planned maintenance and refurbishments slated for Unit 3 are key elements for achieving the targets for 2023, 2027 and 2043.

Existing switchgear is in many cases at or near end of life, but planned maintenance incorporating selective refurbishment and replacement particularly for Unit 3 and maintenance of sufficient spares should enable required life extension targets to be achieved.

Overall, Hydro has addressed major high risk items that have been identified in previous condition reports. Continuing to assess and repair issues as they arise is critical.

Wood has identified the following challenges that need to be addressed for the continued use of the Holyrood Plant in an emergency standby capacity beyond 2023:

1. Human Resources
2. Quick Start Up and Shutdown
3. Boiler Life/ Reliability
4. Fuel Supply and Management
5. Steam Turbine and Generator Reliability
6. Water Supply
7. Civil Structures
8. Continued Condition Assessments

Wood, based on the completion of its condition assessment review, agrees that the capital items proposed by Hydro are both necessary and reasonable for continued safe and reasonably reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023.

Wood agrees with modest investments in studies, engineering, moderate facility additions, and testing to facilitate/establish the potential opportunities faster starts, quicker Unit 3 generator conversions, and for lower minimum load are warranted in the 2020 to 2023 period.

The current operating approval for Holyrood TGS expires August 31, 2021. It includes several 2018 amendments issued after the approval was first released in 2016, including the operation of the mobile diesels.

The approvals of the deferrals of API out-of–service are a regulatory issue being pursued by Hydro for all four main oil tanks. At present there is only an approval for deferral of the API tank inspections for Tanks 1 and 2 to December 2021.

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Appendices:

Appendix A - Wood Letter of Support - Supplemental Capital Request

Appendix B - Holyrood Thermal Generating Station Certificate of Approval

REPORT SYNOPSIS

Project Description and Scope

Wood Canada Limited was contracted by Newfoundland and Labrador Hydro to prepare a "2019 Holyrood Condition Assessment Update study". It was to have several aspects:

- an update of the 2017 Condition Assessment Study for each of the three steam turbine generator units and common facilities at Holyrood TGS, focusing on major things that had changed since the 2017 study
- a review of Holyrood Maintenance Programming
- a review of Holyrood TGS capital plans, identifying additional items for consideration, particularly as it related to standby/emergency generation needs beyond the end of steam generation period.
- a review of Human Resources/Staffing during the periods under consideration
- a preliminary high-level view of the potential opportunities for faster starts, particularly from a cold condition
- a preliminary high-level view of potential opportunities for quicker conversions of Unit 3 from generation to synchronous condensing and vice versa
- a preliminary high level view of lower minimum loads

The study was to look primarily at two periods:

- "Normal Mode Period" - from 2020 to March 31, 2023, where March 31, 2023 was the end of "normal steam generation mode" (as opposed to recent dates of March 31, 2021 or March 31, 2022. It was assumed that Units 1, 2, and 3 would continue to generate electricity at levels comparable to historical until March 31, 2023. Unit 3 would also continue to operate as a synchronous condenser to March 2023 and beyond to 2043 or thereabouts (extended from current March 31, 2021 NLH plans)

- "Standby/Emergency Generation Mode Period" – from end of "Normal Mode period" of March 31, 2023 to a "cold standby/emergency mode" end date likely sometime between March 2027 and March 2033. All three units would be in cold standby generation mode, with Unit 3 synchronous condensing operation continuing to 2043. Faster starts and Unit 3 conversions were key elements of this period.
  - all three HRD units be able to start up within 12 to 24 hours and run at full load on all three units for two to four weeks

Condition Assessment Overview (Chapter 7 in Report)

Holyrood Units 1, 2, and 3 are approximately 50, 49, and 40 years of age in 2019, respectively. They are thus past conventional calendar benchmarks for financial (often technical) end of life of 40 years. The units also have passed or are close to 200,000 hours of operation, which is another benchmark for potential technical end of life/major refurbishment timing.

Nevertheless, there have been many fossil fuelled units in North America (primarily coal units) that have or would have exceeded these guidelines in the past. It is believed that units of the design and age and size of the Holyrood units would technically still be operational in most jurisdictions, except for the impact of sulphur dioxide and nitrogen oxide regulations requiring post combustion controls and more recently greenhouse gas limits in some jurisdictions.

Given their historical seasonal base load and lightly loaded service, the operational age for the majority of its equipment and systems is considered to be more like 30, 30, and 25 years, respectively. The plant has generally 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. They have never been two-shifted like many fossil fuelled units have had to do in North America. The units tend to generate electricity between October and April, loaded at 70 MW at night and 100 to full capacity during peak day periods, generally around 110 to 125 MW. Unit 3 has seen modest synchronous condensing operation since its retrofit in 1986.

There has been considerable work on refurbishing and/or replacing key elements based on extensive condition assessment work, particularly those identified in 2010/11 and 2017 as high risk and those causing reliability issues in 2014-2016. Much of the major equipment has been significantly upgraded and extensively condition assessed.

Holyrood units are expected to be able to meet a March 2023 end of normal steam generation and likely a March 2027+ date for the end of a cold standby/emergency mode generation role, with the planned capital refurbishments and replacements and PM/CM maintenance.

Holyrood Unit 3 is also expected to be able to meet its 2043 synchronous condenser end of life but will require some further significant generator and auxiliaries equipment refurbishments and replacements specific to that role that are identified later in the report. Examples of these over time would include a generator stator rewind, some switchgear, and breakers/motorized switches replacements/refurbishments, as well as some synchronous condensing SSS clutch equipment refurbishments.

Equipment issues identified that should be considered in short term planning (excluding faster starts and shorter conversion time and lower minimum load) include:

- fuel storage tank inspection regulatory extensions (based on existing Condition Assessment reports)
- Units 1, 2, and 3 boiler surface issues (i.e. for surfaces less than ASME minimum thicknesses)
- Units 1, 2, and 3 generator and auxiliaries refurbishment including recognizing Unit 3 long term synchronous condensing use and current operating hours (i.e. stator rewind; generator inspection/overhaul.
- Stage 2 switchgear and control upgrades required for synchronous condensing)
- Stage 1 switchgear assessment of needs for refurbishment/replacements as necessary to support continued operation or connections to station service/black start diesels and CT and lines
- Unit 3 steam chest inspections and repairs as required (checking crack growth)
- Site buried outdoor fire water piping failures requiring short term repairs and selective replacement
- Unit 2 generator inspection and steam turbine valves overhaul in 2020
- Unit 1 turbine steam turbine overhaul and valves in 2021
- Stack regulatory inspections, as well as re-coating for concrete degradation protection
- Condenser water box thickness inspections and repairs as required
- South side oily water separator inspections (repairs/replacements as required)

Capital Improvements (Chapter 13 in Report)

Capital Investments to 2019

Staff and management involved in capital improvements completed since 2010/11 and 2017 at Holyrood should be commended. All of the improvements have contributed to increase the reliability and overall life of the plant. A listing of significant capital improvements in the period 2015 to 2019 is presented in Chapter 5 (Table 5-1).

2019 Capital Plan Investments for March 2021 End of Steam Generation

The table below (Chapter 13 in report) presents the 2019 capital plan which at that time assumed an end of steam date of March 31, 2021 (thus, excludes recent supplemental projects to extend the normal operating mode period beyond March 31, 2021 to March 2023; or boiler overhauls, which are not capital).

Table RS-1
2019-2024 Capital Plan – For End of Steam Service of March 2021

2019 HTGS Capital Plan (2020-2024)						
Year	Project	2020	2021	2022	2023	2024
2020	Rewind Unit 3 Generator Stator	1,359.6	5,789.0			
	Upgrade UPS 3 & 4	266.7				
	Install Plant Heating System (Will be SUPPLEMENTAL)	519.1	6,953.7			
	Upgrade Waste Water Basin Building (Submit for 2021 or SUPPLEMENTAL)	116.7	1,362.7			
	Thermal In Service Failures	1,250.0				
2021	Replace One of North or South Instrument Air Receiver Systems Unit 3		753.0			
	Inspect and Overhaul Stacks		500.0			
	Upgrade Property Fencing		50.0	50.0		
	Replace Stage II Electrical Distribution Equipment		2,513.2	2,269.6		
	Upgrade DCS Controllers / Hardware		250.0	250.0		
	Water Treatment Plant - Acid/Caustic Tank Upgrades		200.0			
	Replace One of North or South Service Air Receivers Unit 3		308.0			
	Thermal In Service Failures		1,250.0			
2022	Upgrade On-Site & Access Roads			500.0		
	Refurbish Biogreen Waste System			100.0		
	Fire System Upgrades			275.0		
	Thermal In Service Failures			1,250.0		
	Light Oil System Inspection and Upgrade			100.0	900.0	
	Install New Lube Oil / Seal Oil Systems Unit 3 (Inc. Assessment of LO Program)			255.0	765.9	
	Overhaul Unit 3 - Generator Only			1,300.0		
	Upgrade 600V VFDs in Wastewater Treatment Plant			250.0		
	Replace existing Stage 1 4160 V AC Breakers as Required			750.0		
	Install Energy Efficient High Bay Lighting System			15.9	609.2	
	Units 3 Generator Upgrades - Slip Rings, Brush Gear, Bearings, Pony Motor and Starter, SSS Clutch, etc..			941.5	784.6	1,273.9
	Upgrade Protective Relaying - Unit 3 Generator (SEL)			500.0		
2023	Cooling Water Pumphouse Refurbishment (stop logs in yr.1, new removable screens, 60 hp pump/motor, Insp. CW				650.0	400.0
2024	Upgrade Ambient Monitoring Stations					250.0
	Water Treatment Plant Upgrades (if required for GSCW, Domestic)					1,000.0
		3,512.1	**19,929.6**	**8,807.0**	**3,709.7**	**2,923.9**
		2020 TOTAL	2021 TOTAL	2022 TOTAL	2023 TOTAL	2024 TOTAL

Wood is substantially in agreement with the elements of the plan. Most of these are for Stage 2/Unit 3 facilities or common facilities and will be required for ongoing plant and Unit 3 synchronous condensing operation. Wood also agrees with the concept that some of the larger items will be re-examined in 2020/2, primarily those not associated with Unit 3's continued use as a Synchronous Condenser and/or are indicated as "SUPPLEMENTAL" and are post 2021.

2019/2020 Capital Plan Supplemental Investments for March 2023 End of Normal Steam Generation

There is no question that Holyrood will continue to need capital improvements, including some dedicated to the generation/steam side of the plant which for this study is March 2023. Some additional capital improvements that may be required are outside of the plant's jurisdiction such as the power transformers and switchyard equipment.

In November 2019, Wood Canada, as part of its initial investigations in this Condition Assessment Update study, was asked to assess NLH's response to the Public Utilities Board (PUB) related to supplemental capital requirements (**PUB-NLH-048 RFI, Reliability and Resource Adequacy Study)** to continue operation until

March 31, 2023. These initially proposed HRD supplemental projects identified for 2019 through 2024 are shown in Chapter 13 in this report).

Wood provided a preliminary Letter of Support of those proposed Supplemental Capital items identified by NLH as being both necessary and reasonable to the continued safe and reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023. In most cases the funds requested allowed the continuation of many of the regularly scheduled major inspections and overhauls (consistent with Original Equipment Manufacturer guidelines) to ensure safe and reliable conditions for continued operation of HTGS. It is reasonable also that NLH had identified some activities that were conditional on the findings of prior investigative work, specifically as an example as it relates to detailed inspection and refurbishment of its primary oil tanks.

In March 2020, Holyrood Long Term Asset Management updated its Supplemental Capital Request and submitted it to the PUB. The list included those shown below:

Table RS-2
March 2020 Supplemental Capital Request

Description	Estimated Cost	Justification
Holyrood TGS Unit 1		
Internal boroscope inspection of Economizer Inlet Header including measurement of ligament cracks to track growth rate.	$37,500	Last inspected in 2017. B&W recommended re-inspection at three-year-intervals to monitor crack growth rate.
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Replacement of Sootblower 17R Aspirating Wallbox and Sleeve.	$22,000	Recommended based on condition assessed in 2019 when temporary repairs were performed to correct corrosion damage. Permanent repairs required to manage risk of sootblower impingement on wall tubes and jamming of moving parts on wall box if not replaced.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Replacement of the following three Down Comer Supports and leaking Header Expansion Joints: • 10th Floor - Cold Reheat Support, West Clamshell, "10B" • 10th Floor- Cold Reheat Support, East Clamshell, "10C" • 8th Floor- East MS, Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the following two observation ports: • 4th Floor - SW "A" Corner • 2nd Floor - SE "D" Corner	$96,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • Outlet Header • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Accelerateed Corrosion of Economiser inlet piping bends on the 6th Floor.	$12,000	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections. Projected wear rates determined from measurements made in 2017 indicate that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.

Description	Estimated Cost	Justification
Holyrood TGS Unit 1		
Internal boroscope inspection of Economizer Inlet Header including measurement of ligament cracks to track growth rate.	$37,500	Last inspected in 2017. B&W recommended re-inspection at three-year-intervals to monitor crack growth rate.
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Replacement of Sootblower 17R Aspirating Wallbox and Sleeve.	$22,000	Recommended based on condition assessed in 2019 when temporary repairs were performed to correct corrosion damage. Permanent repairs required to manage risk of sootblower impingement on wall tubes and jamming of moving parts on wall box if not replaced.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Replacement of the following three Down Comer Supports and leaking Header Expansion Joints: • 10th Floor - Cold Reheat Support, West Clamshell, “10B” • 10th Floor- Cold Reheat Support, East Clamshell, “10C” • 8th Floor- East MS, Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the following two observation ports: • 4th Floor - SW "A" Corner • 2nd Floor - SE "D" Corner	$96,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • Outlet Header • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Accelerateed Corrosion of Economiser inlet piping bends on the 6th Floor.	$12,000	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections. Projected wear rates determined from measurements made in 2017 indicate that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.

Description	Estimated Cost	Justification
Holyrood TGS Unit 3		
Inspection of Boiler Feed Pump Piping Discharge Eccentric Reducer and "Y" for Flow Accelerated Corrosion.	$26,000	Recommended by B&W to prevent in-service failure based on maintenance experience at HTGS . The "Y" Was replaced in 2016 due to advanced Flow Accelerated Corrosion.
Inspection of Main Steam Turbine Terminal to monitor Creep & Thinning.	$32,500	Recommended by B&W at 3-year intervals based on findings of inspections completed in 2017 in which minor degredation and thinning were found.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Refurbishment of the 3rd Floor Southwest corner observation ports.	$82,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Investion of Windbox Corner Attachment failures including design and install of improved attachment method.	$45,000	Required to improve reliability of Windbox corner attachments which are prone to failure most recently causing a forced outage in 2018
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Condition Assessment of Forced Draft Fans.	$45,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$146,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Sampling and Analysis of Waterwall tubes including mechanical properties testing, deposition rate measurement and deposit chemical analysis.	$31,500	Recommended at three-year intervals by B&W to monitor deposit weight density and mechanical condition which will be used to inform chemical cleaning requirments.

Wood, based on the completion of its condition assessment review, agrees that the capital items in the listing above both necessary and reasonable to the continued safe and reasonably reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023. Wood provided a Letter of Support for the requested Supplemental Project list above. A copy of the Letter of Support is attached in Appendix A.

2020/21/22 Capital for Faster Starts, Faster Unit 3 Conversion, and Lower Minimum Load

Wood also believes that modest investments in studies, engineering, moderate facility additions, and testing to facilitate/establish the potential opportunities faster starts, quicker Unit 3 generator conversions, and for lower minimum load are warranted in the 2020 to 2023 period. These aspects will be addressed in further detail and costed as part of an extension to this current study planned for mid to late 2020 by NLH.

For quicker start-ups:

- Conversion of Unit 3 boiler to become the primary (but not exclusive) source of Auxiliary Steam (lowest cost initial option)
  - ✓ Design changes to provide mechanically atomized burners interchangeable with current burners
  - ✓ Operate at 1500-1600kPa continuously using Main Fuel Oil - use smaller burner nozzles on a number of guns which would be interchangeable for cleaning, temperature control. etc.
  - ✓ Modify Foxboro DCS logic (atomizing steam pressure required during normal generation, but not as an Auxiliary Boiler) - some minor logic changes to accommodate each mode of operation.
  - ✓ Use boiler feedwater pumps to supply feedwater at the lower boiler pressures (added maintenance on the BFW low flow control valves), but evaluate redesign of Reserve Feed Water System to supply each unit boiler with a higher pressure, flow controlled, supply of water

- Design and Implement Economizer Recirculation on Units 1 and Unit 2 Boilers
- Design and implement Steam Piping on Units 1 & 2 from the Auxiliary Steam Header to Turbine Gland Steam Systems
- Reinstall Boiler Furnace Cameras on Units 1,2 &3 and Provide Monitors in Control Room
- Install Motor Operators and Controls on Units 1 &2 Boiler Drum Continuous Blowdown Valves
- Install Motor Operators and Controls on Units 1,2,&3 Boiler Lower Waterwall Header Drains
- Implement procedures and training to utilize existing Boiler Temperature Probes on Units 1&2
- Design and Install Unitized Main Fuel Oil Unit Heating Recirculation from Suction Header to Recirc Line to Day Tank
- Design and Install Main Fuel Oil Storage Tank Recirculation on one or more main oil tanks
- Assess and if viable purchase a used simulator (2015 vintage) that appears to be largely compatible with HRD units and is currently available from OPG's Thunder Bay TGS (likely will not be on the market long)

Quicker Unit 3 Conversion from/to synchronous condenser to/from generator and lower minimum loads are not expected to involve any additional significant costs outside of those for quicker start, but will require procedural, work practice, settings, and control logic changes.

These are expected to be able to provide some economic relief and system responsiveness in the 2020 to 2023 period, as well as facilitate any longer term cold standby/emergency operation if that were to prove desirable from a system flexibility and economic perspective (as was the case for the Ontario Power Generation Lennox Thermal Generating Station 4 x 500 MW heavy oil and natural gas steam plant).

Holyrood Plant Maintenance Program Review (Sub-Chapter 5.5 of Report)

As input to the overall 2019 condition assessment update, Wood reviewed the Holyrood plant maintenance program through staff interviews. The primary factor was the effort being undertaken to maintain reliable, safe, economic operation in light of reducing demand for electricity generation, but with ever increasing criticality when it is needed.

The maintenance strategy presently in effect at Holyrood is basically being implemented through a combination of in-house resources for work execution and/or management, external resources for major equipment technical support, overhauls, and specialized services, as well as specialized short-term contractual arrangements with key retired or external staff through 2023. The turbine generator contract expired in 2019, the boiler contract in 2020, and of the 30 service contracts, 6 have expired to date.

Currently many major equipment-based inspections, overhauls, even PM's and CM's are time based. This has been entirely appropriate given its historically consistent operating pattern over the last twenty years or more. This is a key element of the maintenance strategy that would have to change in the post Muskrat era, particularly in the period post March 2021 as generation reduces and then in 2022 or 2023 if the station enters a cold standby/emergency generation mode and with Unit 3 used significantly operating as a synchronous condenser. Rather than a time-based approach, inspections and overhauls and refurbishments/replacements would be condition/equivalent operating hours based, with time-based elements as an influencing factor.

Environmental Regulatory Assessment Post 2020 (Chapter 14 of Report)

Certificate of Approval/Operating Approvals

The current operating approval for Holyrood TGS expires August 31, 2021. It includes several 2018 amendments issued after the approval was first released in 2016, including the operation of the mobile diesels.

Figure RS-1
Holyrood Certificate of Approval


GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Municipal Affairs and Environment

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***October 31, 2016*** Approval No. AA16-105640A

Amendment: ***April 2, 2018***

Expiration: ***August 31, 2021*** File No. 716.008, 716.050.1

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

Essentially the terms and conditions are as follows:

TERMS AND CONDITIONS FOR APPROVAL No. AA16-105640A
April 2, 2018

General

1. This Certificate of Approval is for the operation of a 123 MW Combustion Turbine, Six (6) Diesel Generating Units and a Thermal Generating Station, including power house, wastewater treatment plant, hazardous waste landfill and associated works located at Holyrood, Newfoundland. Extensive future expansion or change of activities will require a separate Certificate of Approval.

2. Certificate of Approval AA16-105640 is revoked and replaced by this Certificate of Approval.

Expiration

108. This Certificate of Approval expires ***August 31, 2021.***

109. Should HYDRO wish to continue to operate the Thermal Generating Station and the Combustion Turbine beyond this expiry date, a written request shall be submitted to the Director for the renewal of this Approval. Such request shall be made prior to ***March 1, 2021.***

There was some concept of employing flue gas desulphurization (also known as "FGD" or "sulphur dioxide scrubbers") and particulate electrostatic precipitators ("ESP's") for HTGS if its life were significantly extended or additional capacity added. The suggestion was included in the GovNL 2007 Energy Plan (" 2007 Energy Plan: Focusing our Energy - basically to replace HTGS or to install scrubbers/precipitators. No requirement was ever formalized.

The approvals of the deferrals of API out-of–service are also a regulatory issue being pursued by Hydro for all four main oil tanks. At present there is only an approval for deferral of the API tank inspections for Tanks 1 and 2 to December 2021.

Greenhouse Gas (GHG) Commitment

Regulatory amendments are also likely required to address the continuation of HRD TGS in the light of current greenhouse gas (GHG) commitments and costs. The current regulatory framework is based on HRD TGS closure in 2021. Unless, current provisions are modified, the generation and use of GHG credits will involve a loss of revenue that will have to be accounted for. The issue of HRD TGS GHG targets themselves is an issue as they tighten with time.

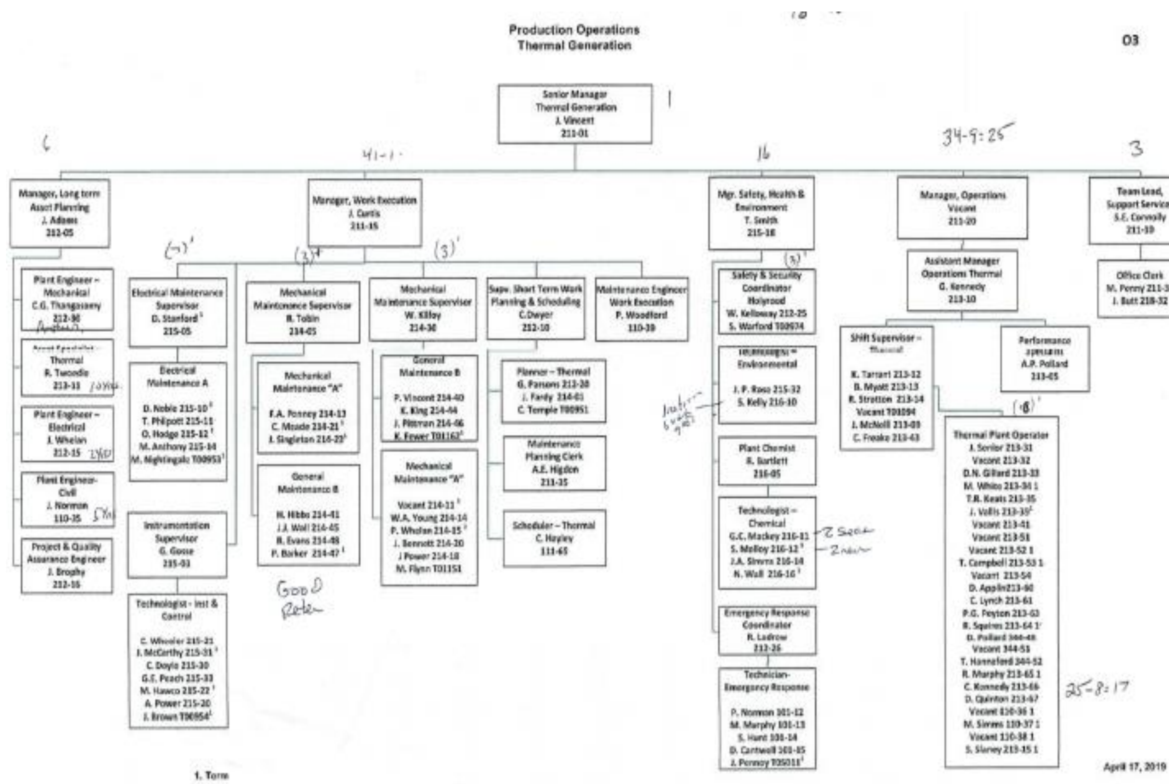
Review of Human Resources/Staffing (Chapter 15 in Report)

Holyrood TGS has experienced significant human resource challenges since it was originally announced that it would be substantially reduced in generation once Muskrat Falls came into service and on standby for two years thereafter.

Several measures have been taken, working with the Union, to minimize or mitigate some of the impacts. There have been experienced temporaries retained using premium rates through March 31, 2021. These are assumed to be extended until the end of steam operations (at least March 31, 2022), to March 31, 2023 for this study. This has left the station with a significant portion of junior staff and/or others less experienced within the Holyrood station specifically. This has had the potential to impact both safety and reliability and is the focus of considerable effort.

"Normal Operating Mode" to March 31, 2023 - The current staffing of the Holyrood TGS would be maintained. There are approximately 101 staff positions (including 10 vacancies and 23 Term personnel). There are also at present about 16 staff positions associated with the existing gas turbine or diesel facilities shown that are being integrated into the "Thermal Division" with Holyrood TGS.

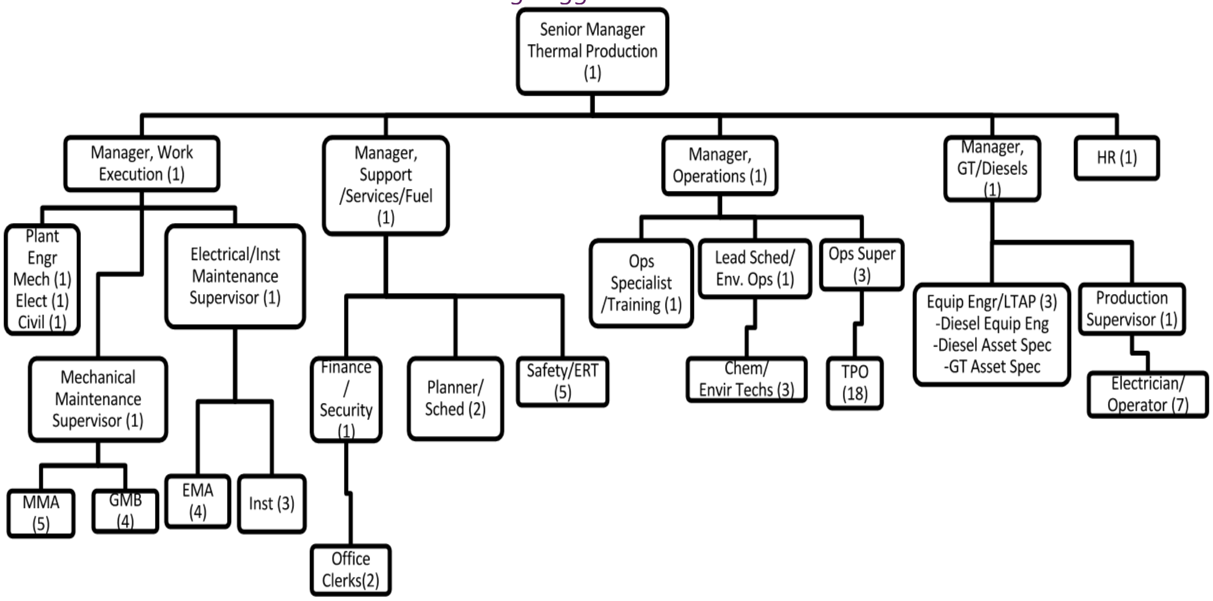
Figure RS-2
Current Holyrood TGS Staffing – Similar for Period to End of Normal Steam Generation, March 2023



"Cold Standby/Emergency Mode Period" after March 31, 2023 - The basis for post March 2023 assumes that all three HRD steam units must from cold standby be able to start up within 12 to 24 hours and run at full load on all three units for two to four weeks. Unit 3 would operate in Synchronous Condensing mode unless needed for generation. Unit/staff "exercising" would also occur twice per year each - the units are started up in a "Fast Start" mode (preferably during the day shift) to exercise both the staff (to maintain staff skills) and the equipment (also identify any maintenance issues that require effort). Numbers and skillsets are determined by the need to be able to start up within 12 to 24 hours and run at full load on all three units for two to four weeks without staffing concerns.

Wood suggests as a starting point for discussion the draft organizational plan below. It includes the Gas Turbine and Diesel staffing. It has about 74 total staff for the Thermal Division (62 HRD TGS plus 12 in Gas Turbines and Diesels). This is down substantially from current level of about 117 (101 at Holyrood TGS and 16 in the GT/diesel areas). The rationale for the positions and change are included in Chapter 15.

Figure RS-3
Wood Staffing Suggestions Post March 2023



<u>Quicker Start Up and Shutdown</u> <u>(Chapter 16 in Report)</u>

In the 1980's and 1990's Ontario Power Generation had a 4 x 500 MW residual oil (and subsequently dual fuel heavy oil and natural gas) fired Lennox TGS station in Kingston (1973-1977 In-Service). It faced mothballing and closure. Despite that it remains the only operational conventional steam cycle generation facility in Southern Ontario. It has maintained that because of its ability to perform fast start-ups, much faster than conventional steam plants. This was achieved through the use of its individual unit deaerator electric heaters that produced steam to keep IP portions of the steam turbines warm enough to proceed through heat soaks without delay. The boilers were kept warm by operating the supplied Boiler Circulation Pumps to avoid long heat up delays.

Holyrood can certainly play an emergency role for expected potential emergency situations where bad weather was expected and plans for Holyrood start-up could be orderly and slow, well in advance. However, it cannot now respond as quickly as desired as it is currently operated and configured in a cold standby mode in the event of an unforeseen outage (which by their nature are major events, even if likely few and far between).

Holyrood TGS is believed to be limited by several factors:

- Internal expectations of operators and NLSO that the start-up is always 2 to 3 days from cold. There has been no real driver in the past to change and justify any associated real or perceived risk.
- Limited availability of auxiliary steam capability in cold standby as configured for oil fuel heating and boiler/steam turbine preheating

Wood believes that the Holyrood can provide much faster start-ups than historically implemented (and lower minimum loads) both for hot standby purposes in the period up to its end of normal generation life (March 31, 2023), as well as in the cold standby/emergency generation period from March 2023 to 2027+. It will require some changes in mindsets with both NLSO and HRD, requiring a more aggressive approach. It will require a series of tests to prove fast start capability and reliability and build confidence. For permanent implementation it will also require some improvements in some systems – fuel, boiler, steam turbines, controls, and if possible acquisition of a nearly new simulator.

There are not many "Options" for faster starts, but rather a series of elements that may have some alternatives.

Element # 1 (Recall Times) - Providing Auxiliary Steam for Boiler startups, including fuel oil heating, atomizing steam pressure for main oil guns, turbine prewarming (a - auxiliary steam to glands, or b - other method such as identified during this study that are "not recommended because it is unproven technology". Options might include:

a. Use Unit 3 Boiler as an Auxiliary Boiler when not being used to generate power. The least costly to implement, but more expensive to operate due to poor efficiency. The advantages would be the ability to convert it back to a power generating unit easily. Testing and an engineered study would be required in order to complete the necessary mechanical and logic changes required.
b. Purchasing and installing an auxiliary boiler which is extremely expensive and is also time constrained with respect to when Holyrood is to go into the Post Steam era and the overall uncertainty as to how long the Post Steam era will last.
c. c- Unit 1 or 2 as source of auxiliary steam (less likely especially for test).

Element # 2 - Provide Economizer Recirculation on Units 1&2. Although not originally designed, its need has subsequently become obvious. Design of these in 2007 had been carried out, but not implemented because Holyrood was being used as a base loaded plant. Unit 3 already has this as it was part of the original design. Not having this recirculation capability may have (but not proven) created the necessity of replacing a number of economizer tubes over the years.

Element # 3 - Ensuring fuel availability at minimum cost (ensure fuel flow and minimal degradation over time using recirculation and heating: a) day tank only; b) day tank and 1 main tank; or c) day tank and all main tanks (assuming 3 tanks #2, 3, 4). Minimize light oil use (switch to heavy oil earlier, changing settings reflecting current heavy oil vs original, and minimize heavy fuel use (minimum number of burners, converted to switchable mechanical/steam atomizers); ensure boiler controllability (drum level control improvements – motorizing blowdown valves); Boiler condition and combustion monitoring (temperature probes; combustion monitoring; Boiler settings and DCS logic modifications reflecting current vs original fuel and changes in equipment practices.

Although not advised for long term operation some of Element #3 may be initially deferred for proof of concept (i.e. temperature probes, combustion TV monitoring). These will be identified during initial discussions with plant.

It is anticipated that the process to arrive at this would involve:

9. Review of recent minimum load test results and procedures and lessons learned. Discuss NLSO expectations and interests.
10. Detail the test and permanent modifications required and their effect on recall time for demonstration of concept testing and for the permanent solution
11. Develop schedule of activities for demonstration of concept testing and for the permanent solution
12. Conceptual engineering for demonstration of concept testing and for permanent solution
13. Cost estimates (capital, O&M, fueling) for options/elements of proof of concept testing and for permanent solution
14. Implementation in late 2020 or 2021 of demonstration of concept, and in 2022 of permanent design if desired.

It is considered critical that the testing and the necessary changes (details - see Chapter 16) be made in late 2020 and 2021. Some of the changes are discussed in the following sub-sections of the report:

- 16.1.1 Convert Unit 3 boiler to primary (not exclusive) source of Auxiliary Steam
- 16.1.2 Design and Install Economizer Recirculation on Units 1 and Unit 2 Boilers
- 16.1.3 Install Motor Operators/Controls all boilers Boiler Lower Waterwall Header Drains
- 16.1.4 Install Motor Operators/Controls boilers 1&2 Drum Continuous Blowdown Valves
- 16.1.5 Add Steam Piping Units 1 & 2 from Auxiliary Header to Turbine Gland Steam Systems
- 16.1.6 Reinstall Boiler Furnace Cameras all units and Provide Monitors in Control Room
- 16.1.7 Use Boiler Temperature Probes on Units 1&2
- 16.1.8 Design/Install Main Fuel Oil Heating Recirculation from Suction Header to Recirc Line
- 16.1.9 Design and Install Main Fuel Oil Storage Tank Recirculation (at least one)

Safe and reliable "Faster Start-up" will involve some incremental capital and operating costs that need to be developed.

Reduced Minimum Load (Chapter 17 of Report)

Wood believes that lower Minimum Loads on all Holyrood units should be achievable, likely from current 70 MW levels to on the order of 30 to 40 MW per unit. OPG's oil dual fueled Lennox 500 MW units were and are typically operated as low as 35 MW.

In the past there was no apparent driver corporately applied to push this given the typical load requirement pattern required by the system – generation from March to November from one to three units at 100 to 150 MW during the peak daytime periods and minimum 70 MW at night – ideal from a life management and reliability perspective.

Lower minimum load operation has a number of potential aspects to consider:

- Provides source of significant spinning reserve if needed
- Provides source of auxiliary steam for faster starting other units and fuel heating
- May be able to provide significant MVAR capability at low loads if required
- Could provide for enhanced hydraulic storage/sale of hydro energy in peak periods offshore
- Allows for fuel rotation in storage, less degradation

It does of course have drawbacks:

- Fuel cost if capacity/energy not required
- Adjustments in settings and control require testing to establish level and confidence
- Additional operation results in possibility of additional maintenance

There really is only one "option" if lower minimum loads are required or desired, which is to focus on operational practices, ensuring settings and operational procedures are suitably and safely adjusted. The steps are:

- Test plan – development and communication/agreement with plant staff and NLSO
- Testing – including interim settings and logic changes to allow lower load
- Procedure documentation
- Communication – Operations and plant staff and NLSO

Improving Unit 3 Changeover: Synchronous Condenser to/from Power Generator
(Chapter 18 in Report)

An onsite review indicated that the majority of controllable time required to complete the task is due to the purging of the hydrogen in the generator casing, first with Carbon Dioxide and then with air before the work permit is established. This typically takes approximately two days. Maintenance staff then completes the re-coupling of the generator to the steam turbine in three 10 hour days. After the permit is surrendered the above procedure to establish a hydrogen environment in the generator casing is then carried out by reversing the above process which takes approximately another two days before the start-up commences. (In going from generating mode to synchronous condensing mode, the cooldown period of the steam turbine cannot readily be reduced.)

A few options have been identified that could be considered to reduce changeover time:

- Eliminate the purging of hydrogen steps – leave generator seal oil system in service with hydrogen in the casing and use sparkless tools during uncoupling and recoupling (i.e. appropriate tools and work methods) and gas monitoring – work protection code likely not an issue but HSE Committee and maintenance staff safety concerns would have to be addressed. Minimal costs. West coast utility had used approach before at their station before its end of steam date.
- Refitting the carbon dioxide and air filling and exhaust systems with larger pipes/capacity and adding carbon dioxide heaters to prevent freezing. Costs, moderate time saving impact.
- Leaving the CO2 in the generator and avoiding air fill step – costs, moderate time saving impact.
- Have conversion work done on 24 hours/day basis vs. current 10 hours /day mode (staff availability, overtime issues)
- Running one or more units (likely Unit 3 first) at very low minimum generation load (30 MW, after demonstration), but maximum MVAR output (100-130+ MVAR may be possible). Issues and characteristics associated include: fuel cost; increased maintenance; excitation system capability verification; spinning reserve capability; auxiliary steam availability for oil heating and faster start of other units and building purposes.

Level 2 Requirements Summary

Level 2 inspections were identified in Chapters 8 to 11 of the report and summarized in Chapter 12. Summary level information on what Level 2 activities should be considered to be undertaken is provided by Major Plant Area, but no costs were included in the scope of this update. Tables RS-1, RS-2, RS-3, and RS-4 are summaries of Level 2 activities identified for Units 1,2,3, and Common, respectively. Priorities assigned by WOOD, with Priority 1 being the highest priority.

Table RS-3 Unit 1 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
8.1.3.8	Unit 1	6723 – Unit 1 Electrical & Control Systems	Monitor cables, bus duct, power centre B AAB2.	3
8.1.3.8	Unit 1	6723 – Unit 1 Electrical & Control Systems	Assess Stage 1 switchgear for a) the one synchronous condenser unit case, including station service supply; b) all three units in cold standby/emergency operation mode after March 2023.	2
8.1.4.8 8.2.10.8	Unit 1	280182 – Unit 1 Electrical & Control Systems	Concrete beam of East Cooling Water Sump,– inspection and repair as required	2

Section	Unit	Asset	Activity	Priority
8.2.1.8/11	Unit 1	6699 – Unit 1 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
8.2.2.8	Unit 1	6708 – Unit 1 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U1 HP feedwater discharge piping	1
8.2.3.8	Unit 1	6708 – Unit 1 Feed Water System HP Heat Exchangers	Assess need for Level 2 inspection of U1 Deaerator Internals	3
8.2.5.8	Unit 1	271316 – Unit 1 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1
8.2.6.8	Unit 1	8777 – Unit 1 FD Fans and System	Level 2 Unit 1 FD fan internals and APH's	2
8.2.7.8	Unit 1	6919 – Unit 1 Stack and Breaching	No Level 2 (Continue stack regulatory inspections. Undertake stack re-coating in 2021-2023 period).	2
8.2.9.8	Unit 1	271309 – Unit 1 Steam Turbine	2021 Level 2 U1 Steam Turbine – stud creep assessment (for those above 850ºF); LP L0 borescope; vibration issues retest as part of inspection/overhaul.	1

Table RS-4 Unit 2 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
9.1.3.8	Unit 2	8152 – Unit 2 Electrical & Control Systems Associated with Generators	Monitor cables, bus duct, power centre B AAB2	3
9.1.3.8	Unit 2	8152 – Unit 2 Electrical & Control Systems Associated with Generators	Assess Stage 1 switchgear for a) the one synchronous condenser unit case, including station service supply; b) all three units in cold standby/emergency operation mode after March 2023.	2
9.1.4.8 9.2.10.8	Unit 2	271486 – Unit 2 Cooling Water Systems Associated with Generators	Cooling Water Sump, intake, and discharge piping – video inspection and repair as required	3
9.2.1.5/8	Unit 2	7786 Unit 2 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
9.2.2.8	Unit 2	7978 – Unit 2 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U2 HP feedwater discharge piping	1
9.2.3.8	Unit 2	8017 – Unit 2 Feed Water System - Deaerator	Level 2 monitor testing of U2 Deaerator Internals	3
9.2.5.8	Unit 2	271326 – Unit 2 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1

Section	Unit	Asset	Activity	Priority
9.2.1.5	Unit 2	7786 Unit 2 Boiler System	Inspect Unit 2 Boiler Stop Valves and based on results, assess removal/refurbish/replace options	2
9.2.6.8	Unit 2	7786 – Unit 2 FD Fans and System	Level 2 Unit 2 FD fan internals and APH's	2
9.2.7.8	Unit 2	7900-Unit 2 Stack and Breeching	No Level 2 (Continue stack regulatory inspections. Undertake stack re-coating in 2021-2023 period.	2
9.2.9.8	Unit 2	271317 – Unit 2 Steam Turbine	2020 Level 2 U2 Steam Turbine – stud creep assessment (for those above 850ºF); LP L0 borescope as part of 2020 valve/generator inspection/overhaul.	1

Table RS-5 Unit 3 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
10.1.3.8	Unit 3	8712 – Unit 3 Electrical & Control System Associated with Generators	Monitor cables, bus duct UAT3 SA T34 aux transformer	3
10.1.4.8	Unit 3	271678 – Unit 3 Cooling Water Systems Associated with Generators	Visual inspection of U3 Cooling Water Sump, intake, and discharge piping in 2021-2023.	3
10.2.1.8	Unit 3	8336 – Unit 3 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
10.2.1.8	Unit 3	8336 – Unit 3 Boiler System	Level 2 inspections of Steam Drum internals	2
10.2.2.8	Unit 3	8611 – Unit 3 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U3 HP feedwater discharge piping	1
10.2.3.8	Unit 3	8571 – Unit 3 Feed Water System – Deaerators	Level 2 monitor testing of U3 Deaerator Internals	3
10.2.5.8	Unit 3	271677 – Unit 3 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1
10.2.6.8	Unit 3	8777 – Unit 3 FD Fans and System	Level 2 Unit 3 FD fan internals and APH's	3
10.2.7.8	Unit 3	8448 – Unit 3 Stack and Breeching	No Level 2 (Continue regulatory stack inspections and monitor degradation of stacks and liners). Undertake stack re-coating in 2021-2023.	2
10.2.9.8	Unit 3	271675 – Unit 3 Steam Turbines	Level 2 inspection and repair Main Steam Chest; turbine studs, LP LO borescope during 2022 generator and turbine valves inspection	1

Table RS-4 Common Facilities Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
11.2.2.8	Common	1297 Waste Water Treatment Plant	Level 2's inspection assessment of the south oily water separator in the 2021 to 2025 period An assessment of the Waste water treatment process equipment/motors is warranted.	2
11.2.1.7	Common	Oil Storage	Tanks 2,3,4 inspections and repairs if extension not granted – per API letters (for 2023 Life and for beyond 2023)	1
11.2.2.5	Common	Waste Water Treatment Plant (WWTP)	Level 2 Condition Assessment of the Oily Water Separator system (South)	2

Conclusions (Chapter 19 of Report)

The following is a summary of the major conclusions based on the review of the issues and condition assessment documentation in this report. They are intended to highlight the key issues at a summary level. More detail is provided in Chapter 19 of the report.

Station and Units

1. Holyrood's overall condition is fair to good, considering its age. Units 1, 2, and 3 were installed in 1969, 1970 and 1979 respectively and are therefore approximately 50, 49, and 40 years of age respectively as of 2019. The units have typically run seasonal base load between 50% and 100% MCR, and not cycled, not two shifted, not overpressured. Given this, the condition of the units and the majority of major equipment/systems are more consistent with "operational ages" on the order of 30, 30, and 25 years, respectively.

2. Units 1, 2, and 3 have respectively operated about 200,000+ hrs, 200,000+ hrs, and 165,000 plus 55,000+ hrs synchronous condenser as of December 2019 (with very few starts/stops). Operating hours of 200,000 is typically when many older facilities require major refurbishment/rehab work or retirement. Nevertheless given Holyrood's operating pattern and the extent of refurbishment and replacement that has occurred since 2010 (i.e. boiler surfaces, water supply, roads, air compressors, pumps, turbine overhauls, generator rewinds, exciter systems), this has been significantly mitigated..
3. The plant, with ongoing maintenance and inspection and current base and supplemental capital investment, can safely and reliably make the current March 2021 and an extended March 2023 end of generation date, and with Unit 3 generator stator rewind and refurbishments a 2043 Unit 3 synchronous condenser end date
4. Units 1, 2, and 3 can with the planned investments operate reliably and safely in generation mode to March 2023 generation end of life, and beyond in an emergency/standby mode to 2027+.
5. Plant HR issues have been and continue to be an issue. Significant numbers of "Term staff" are employed and currently have letters which were recently extended to March 2022.
    a. Staff levels to the end of normal steam period should continue at current levels, reducing to about 74 (including 12 diesel and gas turbine staff) for post March 2023 cold standby/emergency generation period
    b. Start/stop exercising of equipment and employees is needed, particularly in post normal steam period. Consideration should be given to procuring a simulator, such as a nearly new unit available from Ontario Power Generation (OPG) Thunder Bay station and readily convertible to Holyrood.
6. 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 the March 2023 end of Normal generation date, and identify issues for the post 2023 period.

7. Current inspection/overhaul intervals should be maintained to the end of 2022, but post 2022 inspections/overhauls should be based on condition and equivalent operating hours based criteria to be determined
8. Uncertainty over the plant future is impacting many decisions, such as:
    a. Fuel tank #'s, inspections, upgrades – regulatory decisions
    b. Investments and trials of "Faster Start", "Lower minimum load operation", and "Quicker Unit 3 conversion to/from synchronous condensing"
    c. Steam turbine valve and turbine overhauls; major equipment overhauls and replacements
    d. Scope of boiler overhauls
    e. Generator rewinds and overhauls
    f. Controls, Performance improvements

Site Conditions

1. The site is in generally in good condition, but some underground sections of the site fire water system are in poor condition requiring repairs in 2020 and/or 2021.
2. The on-site landfill is nearing end of life and requires management as well as possible expansion or replacement.

Common Facilities

1. The plant has implemented a number of measures to ensure sufficient oil delivery capability, while reducing costs (i.e. deferring major tank inspection expenses). Facilities are able to meet a 2021 end of generation service date, but will require more effort for March 2023 and beyond:
    a. Tank 1 inspection and life extension requires significant repairs. Plant operation given reduced generation levels may eliminate the need for Tank 1, but implementation would require of review in more detail of additional issues such as any regulatory changes and winter readiness risks.
    b. Studies of Tank 2, 3, and 4 have shown that regulatory extensions for out of service inspections and refurbishments can be extended to 2027+. Requests have been submitted to Regulators, but no decisions identified. These need to be either granted or inspections/repairs made for both March 2023 and cold standby/emergency mode period.
    c. Retrofit of a Main Oil Tank recirculation system to at least one tank (or two) may be highly desirable to promote mixing in the post 2023 period during long periods of storage.
    d. Retrofit of a Day Tank recirculation system (preferably from Unit 3) may be highly desirable to promote mixing in the post 2023 period during long periods of storage.
2. Circulating water intake and discharge structures and sumps and large concrete pipes from the pumphouses to the condensers and to the discharge siphon pits were planned to be Level 2 inspected in 2020. They are likely to meet a 2023 end of normal steam generation service life. Flexibility post 2023 for synchronous condensing operation exists. Post 2023 use is likely acceptable, subject to normal PM's and submersible camera inspections driven by condition.
3. Some improvements have been made to the water treatment plant clarifier, sand filters, and clearwell. Regular PM's and any resulting work should mitigate unplanned shutdowns during the pre and post March 2023 periods.
4. A new building heating system (possible auxiliary steam supply) needs to be operational before March 2023. At present, no plan has been settled upon. Operation of Unit 3 boiler as a steam source for building heating, but also for cold standby/emergency readiness for quicker start-up including fuel preheating should be one of options examined.
5. The wastewater basin building remains in poor condition and access is restricted for human health reasons.

Six 2 MW Black Start Diesel Generators, 120 MW Gas Turbine, and TS Switchyard Facilities

The six 2 MW Black Start Diesel Generators, 120 MW Gas Turbine, and TS Switchyard Facilities were not specifically addressed in this review, but with regular maintenance and overhauls should remain in good condition for use through 2030 and beyond.

Holyrood TGS Facility Management

1. Overall Holyrood TGS facility management is excellent with a demonstrated practice of continuous improvement under difficult circumstances. 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. Holyrood TGS has experienced significant human resource challenges. Several measures have been taken, working with the Union, to minimize or mitigate most some of the impacts such as using experienced "Term" staff retained through March 31, 2022.

Environmental / Regulatory Assessment

1. The existing Certificate of Approval expires August 31, 2021. It covers among other things the Holyrood TGS, the Holyrood CT and the six diesel generators. A new Certificate of Approval and Operating licenses will be needed to extend operation for dates beyond March 31, 2021. A new application is to be submitted in writing by March 1, 2021. Even with a closure of Holyrood TGS in March 31, 2021, a new application for the diesels and CT would be required.

2. A new GHG plan will be needed for period beyond March 2021, and/or additional costs for GHG credits will have to be accounted for.

Quicker Start Assessment

1. Quicker starts are possible from hot (4-8 hours)/warm (<8 hours) for the period up to March 2023 without major modifications to the plant equipment. 2020 to 2021 is the time to engineer, test, and implement modifications for quicker start and lower loads for both the pre-March 2023 period, as well as for the cold standby/emergency mode period post March 2023

2. Wood believes that all units can be started at least in 8-12 hours for one unit and less than 24 hours for the second unit with modest capital investment and operation changes. A number of changes need to be made in order for that to happen, and are required during the time frame of 2020-2022 to demonstrate their viability and implement (See Chapter 16)

Improving Unit 3 Changeover to/from Synchronous Condenser to Power Generator

1. A significant reduction in the conversion time on Unit 3 from synchronous condenser to generator is possible. Options include:

    a. Leaving the hydrogen in the generator during conversion using revised work practices and sparkless tools and monitoring.

    b. Improving the methods of purging the hydrogen from the generator casing: adding larger vents or increasing the carbon dioxide line sizing along with a carbon dioxide heater to prevent freeze ups of CO2 as it is being introduced.

    c. Leaving the CO2 in the generator and avoiding air fill step

d. Have conversion work done on 24 hours/day basis vs. current 10 hours /day mode (staff availability, overtime issues)

e. Running one or more units at low minimum generation load (30 MW, after demonstration), but maximum MVAR output (100-130+ MVAR may be possible). Fuel cost; increased maintenance; Excitation system capability verification; spinning reserve capability; Auxiliary steam availability for oil heating and faster start of other units and building purposes.

Holyrood Capital Plan Assessment

a) Staff and management involved in capital improvements completed since 2010/11 and 2017 at Holyrood should be commended. All of the improvements have contributed to increase the reliability and overall life of the plant.

b) Wood supports HRD's 2019 capital plan for an end of steam date of March 31, 2021

Holyrood will continue to need capital improvements, including some dedicated to the generation/steam side for an end of steam life of March 2023. Wood supports those supplemental capital projects identified by NLH in March 2020 as being both necessary and reasonable to the continued safe and reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023, as noted in the Wood Letter of Support included in Appendix A.

2020/21/22 Capital for Faster Starts, Faster Unit 3 Conversion, and Lower minimum Load

Wood believes that modest investments in studies, engineering, moderate facility additions, and testing to facilitate/establish the potential opportunities for lower minimum load and faster starts and quicker Unit 3 generator conversions are warranted in the 2020 to 2022 period. These costs are to be identified as part of an extension to this study planned for mid to late 2020. These are expected to be able to provide some economic relief and system responsiveness in the 2020 to 2023 period, as well as facilitate any longer term cold standby/emergency operation if that were to prove desirable from a system flexibility and economic perspective.

Recommendations (Chapter 20 in Report)

Overall Station and Units

1. Maintain the ongoing inspection, testing, maintenance and PM activities through the end of steam normal operation mod period to March 31, 2023, adjusting to a condition/equivalent operating hours basis after the end of 2022.
2. Develop condition based and equivalent operating hour based inspection/overhaul system for post 2022 period and overall PM process, but adapting to condition and equivalent operating hour basis.
3. Assess and continue Level 2 condition assessment task inspections and testing identified in Chapters 8 to 11 (summarized in Chapter 12) through March 2022/23 generation end of life, particularly on boiler and high pressure piping components.
4. Develop and implement an optimized plan for station switchgear (Stage 1, Stage 2) addressing a combination of spare components, replacement, and sparing to maintain Unit 3 synchronous condensing capability and station reliability without interrupting normal unit operation.
5. Undertake a Unit 3 generator stator rewind for post March 2021 synchronous condenser operation, as well as generator refurbishment program (including SSS clutch refurbishment

Common Facilities

1. Repair buried fire water system – undertake immediate repairs as required and plan for medium term targeted replacements.

2. Undertake ongoing integrity inspections of single contingency failure candidates such as the dam at Quarry Brook, and the original water treatment plant clarifier, sand filters, and clearwell.
3. Implement a plan for a new building heating system (auxiliary boiler/steam or electric) needed after post steam period.

Six 2 MW Diesel Generators, 120 MW Gas Turbine, and TS Switchyard Facilities

1. Maintain maintenance and overhauls program.

Environmental / Regulatory Assessment

1. Initiate process to submit in writing by March 1, 2021 an application for a revised Certificate of Approval for the Holyrood site facilities.
2. Develop a new GHG plan for period beyond March 2021, including any additional costs for GHG credits will have to be accounted for to address operations beyond March 31, 2021.

Quicker Start Assessment

1. Develop in 2020 as part of an extension to this study a plan and test program to develop a quicker start program including costs (testing, capital and OMA), work process and settings changes, schedule, 2020/21 test program to determine the optimum path.

Management

1. Continue to implement best practices, in a difficult environment.
2. Continue to monitor staff capabilities and find ways to augment staffing to optimize safety and reliable operation to end of generation life of March 2021 or March 2022 or March 2023, as well as for Unit 3 synchronous condensing to 2043.
3. Develop and maintain a succession planning process.
4. Develop and maintain a contingency plan for Unit 1 and 2 generation emergency operation to 2027+.

1. Background

1.1 Study Background

Newfoundland and Labrador Hydro requested in an RFP in 2019 Wood PLC to provide a report including a concept level focused update of the 2017 Holyrood Level 1 Condition Assessment Update. The 2019 Holyrood TGS Condition Assessment Update of the 2017 Holyrood Condition Assessment was to be consistent with an EPRI (Electric Power research Institute) Level 1 Condition Assessment and both less extensive and essentially augment the original 2010/11 Level 1 Condition Assessment study. The result would be a significantly reduced final report deliverable.

The 2019 Holyrood TGS Condition Assessment Update report would also address the issues associated with Life Extending the facility, including life extension regulatory issues and a high level concept review for Cold condition Fast Starts, reduced Unit 3 synchronous Condensing Changeovers, standby/emergency generation mode staffing,.

The 2019 Holyrood TGS Condition Assessment Update report would consider an end of normal steam generation mode of March 2023 with Unit 3 synchronous condensing operation continuing to 2043 or thereabouts ("Normal Mode") (extended from current March 2021 NLH plans). It also considers a cold standby/emergency generation mode ("standby/emergency mode") from March 2023 to an end date sometime beyond March 31, 2027, with Unit 3 synchronous condensing operation continuing to 2043. Up to March 2023, the generation and synchronous generation pattern would be similar to historic norms. The standby/emergency generating pattern would consist of each unit being "exercised" twice per year for two days pattern (started in fast start mode and run up and maintained at between minimum load and full load for two days then shut down), plus an unplanned emergency operation once every five years with all three units at full load for 2 to 4 weeks started as quickly as possible from a cold condition.

The 2019 report would update the basic operational/historical data, overview the whole plant systems for criticality, review condition assessment/maintenance/capital work since 2010/2017, review operational performance since 2017, and consider the plant's role to March 2027+ (possibly 10+ years (2033). Its primary focus areas were to be related to the boilers and related critical auxiliaries, the steam turbine and generator and related critical auxiliaries, the critical plant electrical and control system components, critical staffing issues, and critical Balance of Plant high priority systems/equipment identified in the 2010/11 and 2017 condition assessment work.

The recommended high priority investments were compared to the completed and planned capital investments to determine future requirements. Further to the capital investment, a review of the inspection findings and plant programs was used to evaluate if a revision to the risk level is necessary.

An onsite interview of station staff was held. The interview provided insights and information regarding the capital and maintenance program, and recent condition assessments.

The Level I report in 2010/2011 identified the major "High" risks for each component. A risk level was assigned based on the likelihood and consequence of failure. The risk was assigned as "high", "medium" or "low".

This update of the 2017 condition assessment takes into consideration the 2017 risk level evaluation and the latest findings from Level II assessment and other follow-up condition assessments inspections. Management programs are also credited where applicable. The programs are assumed to be capable of identifying and correcting issues. The programs are assumed to be active, and to remain so for the remainder of the plant life.

1.2 General Description of Holyrood Thermal Generating Station

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

Holyrood Thermal Generating Station is capable of supplying about 20% of the Newfoundland and Labrador grid when all three units are in operation at full MCR (maximum continuous rating). Typically, the units operate between a minimum load of 80 MW's and 150MW's when in operation. Although Holyrood can be called on to supply power to Newfoundland grid anytime during a 24-hour day 365 days a year, normally the plant has primarily been called on to operate during the winter season only. Unit 3's generator is also capable of synchronous condenser operation as required for grid voltage control by uncoupling the generator and turbine shafts. Operating the seal oil pumps to ensure the hydrogen remains inside the generator casing is also required for the generator seals during synchronous condenser operation.

Units 1 and 2

Units 1 and 2 built in the late 1960's as a #6 fuel oil fired 150 MW unit. These two units were modified in 1987 to increase their capability to 175 MW's.

Boilers: The units are equipped with Combustion Engineering (now Alstom) tangentially fired natural circulation boilers. The boilers have 12 burners, four on each of three levels. They were designed to fire a 2.5%S residual crude oil, but in 2007 their fuel was changed to a 0.7% sulphur oil to reduce sulphur dioxide emissions, as well as particulate and sulphur trioxide. They do not have low NOx burners or "Overfire Air (OFA)" for low NOx operations. They also have no particulate capture after the air preheater. They were originally equipped with flue gas recirculation for reheat temperature control, but that was removed earlier in its life. The furnace is a pressurized furnace design and hence has a forced draft fan (currently with a variable frequency drive, but no induced draft fan. As a consequence, considerable effort in recent years has gone into assuring minimal furnace leakage into the plant. The units have no economizer recirculation and no auxiliary steam to steam turbine glands for steam turbine preheating (Unit 3 does have both).

Steam Turbine Generators: The steam turbine generators are General Electric three-cylinder HP/IP/double flow LP 3600 rpm tandem compound turbines, and G.E. hydrogen cooled generators. These two units were modified by GE in 1987 to increase their capability to 175 MW's. The HP turbines throttle pressure was increased to 13.1 MPa at a superheat temperature of 538oC. Units 1 and 2 turbines are unique in that they are not equipped with a main turbine shaft driven oil pump. They also have chain driven turning gear motors in the front of the unit, which have in recent years had some reliability issues.

The units rely solely on two AC motor driven pumps and a backup DC motor driven pump to supply lubrication oil to the bearings and generator seals. The turbine lube oil tank holds approx. 2600 U.S. gallons of Turboflo R&O 32 lubricating oil. The 3 lube oil pumps are located in the turbine lube oil tank on elevation 11ft 2 inches (ground floor) with only the motors exposed on top of the tank. These tanks are directly below the main steam stop and reheat and intercept stop valves of the units. A separate seal oil system was added in approximately 1988 which backup's the AC lube oil pump supply to the generator seals as necessary. The new seal oil unit has two AC driven seal oil pumps along with a DC seal oil pump and a vacuum treating system located directly below the generator on or about elev. 11 ft. 2 in.

The turbine units are controlled using a separate Mark V Electro Hydraulic Control governing system located on the ground floor @ elev. 11ft. 2 in. The system uses a separate hydraulic pumping unit with two AC driven pumps to provide power oil to the stop valves, control valves, and the combined reheat stop and intercept valves.

The GE Hydrogen Cooled Generator supplies 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. Normal hydrogen gas pressure in the generator casing is 310 kPa.

<u>Unit 3</u>

Unit 3 is a 150 MW unit and was added in 1977.

Boiler: Unit 3 has a #6 fuel oil fired Babcock and Wilcox front wall-fired, natural circulation boiler. It has 9 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), 541.6 ºC (1005+/-10ºF) of superheated steam, and 125.1 Kg/s (993,000 Lbs/hr) of reheat steam at 3716 kPa (539 psig), 541.6ºC (1005ºF). Unit 3 does have an economizer recirculation line and auxiliary steam to steam turbine glands for steam turbine preheating.

The boiler has two x 50% Forced Draft (FD) fans driven by 1500 HP, 4.16 kV induction motors. Each of Unit 3 produce about 139.5 m3/s (295,200) ACFM at 8.8 kPa (35.23" w.g.) at 35ºC (95ºF). It has two x 50% Ljungstrum Type 22 ½ VIRX 44 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 two x 50% Ljungstrum air preheaters Type 22 ½ VIRX 44, 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 typically are designed to enable suitable operation down to -5ºC (20ºF) 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 ºC. Its main steam flow is about 121 Kg/s (960,644 Lbs/hr) at rated flow and up to 135 Kg/s (1,072,000 Lbs/hr) at VWO.

Unit 3 turbine generator, unlike Units 1 and 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 and various other valves associated to the unit.

The turbine lubricating oil tank sits away from being directly underneath the HP turbine at an elevation slightly higher than the ground floor of 11 ft 2in. and has a capacity of 4,754 U.S. gallons. The total system oil capacity is 6495 U.S. gallons of oil. Unit 3 is unique in that the lube oil tank contains three pumps. One is called the AC Motor driven "Aux Oil Pump" operating at a discharge pressure of 1210 kPa which supplies bearing oil and power oil (relay oil) to drive the Main Stop Valves, Control Valves, and Combined Reheat / Intercept valves when the unit is being started up or shutdown and the turbine speed is less than 3600 rpm. The AC "Flushing Oil

Pump" and the "DC Flushing Oil Pumps" operate at a discharge pressure of 315 kPa and 272 kPa respectively to provide lubrication to the bearings while the unit is on turning gear or as the backup to the AC Oil Pump when the generator is being used as a synchronous condenser.

Unit 3 has a Jacking Oil Pump which is used prior to the unit being put on turning gear being placed in service to lift the turbine rotor off the bearings. The Jacking Oil Pump is located next to Turbine Lube Oil Tank on elevation 11 ft 2 in. with a discharge pressure of 15.5 MPa with a flow rate of 11 USgpm. It is started and remains in service until the turbine reaches 2000 rpm on start-up and it restarts on shutdown at approx. 2200 rpm.

Unit 3 has a separate seal oil system tank with two AC seal oil pumps and a separate vacuum treatment system located on elev. 11 ft 2 in. directly underneath the isolated phase bus for G3. Unlike Units 1 and 2, the Unit 3 seal oil system is required to be in service anytime the generator casing is under a gas pressure from any source.

Condenser: The Condenser is a Foster Wheeler design with 1842 m2 (65,025 ft2) of surface. They are serviced by 2 x 100% duty vacuum pumps to maintain a 1" hg pressure at MCR.

Cooling Water system: The Cooling Water system feeding the condenser receives seawater cooling from two x 50% cooling water pump systems located in Stage 2 Pumphouse. Each pump can provide about 35,700 USGPM (between 33,300 to 37,500 USGPM depending on tide) or about 3785 L/s (60,000 USGPM) operating together. The CW pumps receive water from 2 x 100% (30,000 USGPM) Link Belt double entry traveling screens.

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 Low Pressure heaters, one Deaerator feedwater heater and three High Pressure heaters after the boiler 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. Either can be 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 1829 m (6000 ft) head. Each is driven by a 3550 rpm, 2350 hp, 4.16kV, 3 phase induction motor. There is no VFD or fluid coupling, as is common at other larger units. Three HP heater are installed - HP heaters HP4, HP 5, and HP6. They are designed to raise the feedwater temperature to the necessary economizer inlet temperature. There is no redundancy, but each can be bypassed as necessary.

Condensate System: The Condensate System consists of two x 100% condensate extraction pumps 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 pushes condenser water through the gland steam condensers, the LP heaters, and then into the deaerator heater. The pumps are controlled to keep about 22" 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, plus a 2nd high level tank originally intended for Unit 4 as well as associated piping, transfer pumps, and valving. Each is about 90,850 L (24,000 USG). The transfer pump can transfer water between units and be used for boiler filling and boiler washing. They can provide up to 18.9 L/s (300 USGPM) at 105m (345 ft) head.

Common Systems

A couple of relevant similarities were identified on both sets of turbine generator units.
On all three units, the lubricating oil supply pipes are located inside the common bearing oil return line to the lube oil storage tank. If a failure of the lube oil supply line occurred, it would be detected by alarms indicating a "high bearing temperature", or a definite reduction in lube oil flow to the bearings as indicated by the reduction of flow as seen in the bearing oil drain line sight glass would be evident.

Fuel Oil Storage & Delivery

Fuel Oil is delivery by tanker to the unloading docks and from there delivered by electrically heat traced pipeline to the Holyrood Fuel Oil Storage tank farm. The tank farm consists of four 33,710 m3 (212,000 bbls) tanks. Each tank has a suction heater for temperature control of the oil discharge, as well as two platform immersion heaters in the tank itself (non-functional). Steam from the auxiliary steam system provides the thermal input. Condensate is discharge via steam traps to drains. A 16" radial pipe to the 18" main supply header takes the oil from the tank farm by gravity flow to the Day Tank. There is no recirculation within the tank or from back to the tank farm from the powerhouse. The station with all units at full load consumes about 120,000 to 130,000 bbls per week. Tankers supplying Holyrood with heavy oil originate from Texas, and take about 4 weeks from order to delivery, depending on weather, ship availability, and fuel availability.

The heavy oil day tank was replaced with the addition of Unit 3. The tank provides gravity flow to the supply pumps on each of the individual units. Unit 3 has a maximum 10.08 Kg/s (80,000 Lb/hr) requirement for example supplied by 2 x 100% positive displacement pumps through 2 x 100% fuel oil steam heaters providing 99oC (210oF) oil to the units. There is a bypass around the day tank from the main tank farm, if required.

There is a light oil system for use in lighting off the steam generators from a black start when atomizing steam is not available for firing with #6 oil. The light oil is fired in the bottom level of burners. The light oil is provided from the station light oil tanks via a header to unit light oil pumps. Atomizing air is provided for the fuel and for purging on burner shutdown. There are two x 100% positive displacement pumps providing about 1034 kPa (150 psig). There is a recirculation system back to the day tank from the burner front header.

Compressed Air: Compressed air systems are provided for both Stage 1 and Stage 2. Stage 2 has two two-stage water cooled rotary screw Atlas Copco compressors to the Service Air System – about 0.31 m3/sec (650 CFM) at 793 kPa (115 psig). A portion is drawn from service air receivers and filtered and dried for use as Instrument Air. Cooling water is provided from the General Service Water System – total of about 1.85 L/s (30 USGPM) for the cooler and aftercooler requirements for each compressor.

Holyrood Simple Cycle Gas Turbine

A 120 MW simple cycle Westinghouse 501D5 oil fueled emergency Gas Turbine Generator is located at the Holyrood Thermal Generation Station (HTGS) site. It has up until recently in 2020 not been a part of the HTGS responsibility, but rather has been a TRO facility. It does serve as a black start unit for the station and to provide system emergency power. It was originally intended to be used occasionally used for system support during system maintenance periods as well during Holyrood Unit outages. It has however seen fairly extensive use in last few years. It is not a part of this 2019 Condition Assessment Update, but it is in reasonably good condition, as a result of its young age and limited use. Its higher than expected use and its use of light oil for fuel and water injection for NOx control does mean that planned maintenance (burner inspections, minor and major overhauls) has been earlier and more frequent than planned.

There is also an older 13.5 MW black start Gas Generator on site that was part of the 2010 Condition Assessment. It consists of 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 was installed 11/7/1966 and had significant repairs in 1978, 1986, 1991 and 2007. This unit has been decommissioned and is no longer operable. It is not considered within the 2017 condition update or this 2019 Condition Assessment Update.

Diesel Generators (Black Start/Emergency)

There are six 2 MW Caterpillar trailer mounted oil fuelled diesel generators (derated to 1.5 MW) on site. They were installed as rental units initially as a replacement for the 13.5 simple cycle gas turbine. They were purchased outright in 2016 and have also been used for emergency power to the system. Currently only five of the six can operate at a time. An additional 90,000 litre fuel tank was installed in 2017.

As emergency units, they were originally equipped with only short stub stacks. Given their current potential use and the ground level concentration of some pollutants, they were retrofitted with taller stacks designed to meet ground level concentration requirements.

They are not a part of this 2019 Condition Assessment Update, but are in reasonably good condition, as a result of their young age and limited use.

Buildings

Main Buildings: The main buildings on site are the Main Powerhouse (Boiler house, steam turbine hall, administration building, and water treatment plant), the Waste Water Treatment Process Building, the Waste Water Treatment Basin Building, the Stage 1 Pumphouse building, and the Stage 2 Pumphouse Building. These are generally steel-clad buildings and 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 tend to have insulated, steel clad roofing.

Peripheral Buildings: The peripheral buildings at Holyrood Thermal Generation Station (HTGS) include several small buildings on the site include:

- 7284 – HRD Training Centre
- 7287 – HRD Guardhouse
- 7288 – HRD H2 and CO2 Storage Building
- 7302 – HRD Shawmont building
- 7303 – HRD Main Warehouse

There is also the Chemical Storage Building, the Pipe Shop, and the Emergency Response Building. Some buildings are pre-engineered steel buildings that sit on concrete foundations and some are traditional steel buildings with concrete foundations.

Powerhouse Heating and Ventilation: Steam type unit heaters are currently provided throughout the building, as well as door heaters on the Stage 2 access doors. The Stage two heaters included 25 unit heaters (4740 kJ/min – 300,000 BTU/hr) – some of which have failed. There are five stage 2 door heaters (19,870 kJ/min; 1,130,000

BTU/hr). There have been several assessments of the type of system that should be employed primarily for building heating once the station goes into standby mode.

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 ensuring that neither excessively cold or warm temperatures nor drafts nor negative pressures occur in the powerhouse. For stage two, there are two roof vents and six horizontals near roof vents.

PumpHouse Heating and Ventilation: Four Steam type unit heaters are provided in the Stage 2 pumphouse. (2286 kJ/min – 130,000 BTU/hr) There are one Stage 2 pumphouse door heaters (19870 kJ/min – 1,130,000 BTU/hr). The building also has two roof ventilating fans for summer.

2. Project Description and Scope

Wood Canada Limited responded to an RFP and was contracted by Newfoundland and Labrador Hydro - a NALCOR Energy Company to prepare an update of the 2017 Condition Assessment Study for each of the three steam turbine generator units at Holyrood. The intent was to focus on major things that had changed since the 2017 study (primarily the boilers and related critical auxiliaries, the steam turbine and generator and related critical auxiliaries, the critical plant electrical and control system components, critical staffing issues, and critical Balance of Plant high priority systems/equipment identified in the 2017 work).

The study was also to address the potential issues associated with life extension of the facility:

- an end of normal steam generation mode ("Normal Mode") of March 2023 (extended from current March 31, 2021 NLH plans) and Unit 3 synchronous condensing operation continuing to 2043 or thereabouts
- a cold standby/emergency generation mode ("standby/emergency mode") from March 31, 2023 to an end date at least March 31, 2027, with Unit 3 synchronous condensing operation continuing to 2043

2.1 Study Basis

The basis for the study is the period to March 31, 2023 in a normal operating mode (likely with decreasing generation over time between 2020 and 2023), and also from March 31, 2023 when normal steam generation at Holyrood is assumed to cease and the units are in cold standby to March 31, 2027 (possibly 10+ years to 2033) as follows:

- 2020 to March 31, 2023 Generation Life
  - ACF/Pattern: Historical data basis
  - Reliability: High, similar to current
- March 31, 2023 to March 2027+ (Possibly 2033) Cold Standby/Emergency Generation
  - All unit's full load capacity required; ACF forecast table (Approximate)
  - Units exercised for equipment and staff – start-ups twice per year each for 2 days at minimum to full load
  - Emergency Generation – all unit's full load for 2 to 4 weeks once every 3 to 5 years initially
  - Operating Pattern Likely - Hot/Cold Standby – Quicker Time to Return
  - Historical Reliability/Availability of generation
- Synchronous Condensing 2020 to 2043 - Capability Limited to Unit 3
  - Operating Pattern and Requirements - Unit 3 SC Operation as required; quicker switchover
- Standby Peaking/Emergency Gas Turbine Operation – Outside Scope
- Standby Peaking/Emergency Black Start Diesel Operation – Outside Scope
- Subsequent Equipment Condition Analyses – Timing/Scope

2.2 Study Focus

As a part of planning for March 31, 2023 through March 31, 2027+, Nalcor continues to undertake a variety of detailed focused Level 2 Condition Assessments and repairs to ensure reliable and safe operation of Holyrood units through the period. It was accepted that an update of the 2017 overall Level 1 Holyrood Condition Assessment update would be appropriate, reflecting major changes (improvements and degradations) since 2011/2017. Unit 3 will continue to provide synchronous condensing capability, possibly through 2043

In principle the 2019 HRD TGS Condition Assessment Update reflects the fact that Holyrood Units 1 through 3 were installed in 1969, 1970 and 1979 respectively and are therefore in 2019 about 50, 49, and 40 years old, and thus past the conventional calendar benchmark for financial (often technical) end of life of 40 years and would frequently have been retired/decommissioned. It is also true that the much of the unit equipment (that not replaced or extensively refurbished) has passed or are close to 200,000 hours of operation which is another benchmark for technical end of life/major refurbishment timing.

Nevertheless, there has been considerable work on refurbishing and/or replacing key elements that were identified in 2010/11 and 2017 as high risk and were causing reliability issues in 2014-2016. Also, it has to be recognized that that the units have not been overly stressed – they have not been two-shifted; and load cycling has been modest typically between 50% MCR and about 90% MCR. The units were also upgraded in the 1980's to 175 MW from 150. The major equipment has been significantly upgraded and extensively condition assessed.

Most major and high-risk issues identified in 2010/11 and 2017 in the Condition Assessment and update have been addressed and rectified. The major equipment issues remaining are primarily related to continued reliable boiler operation (related primarily to the fact that it is heavy oil fueled). Others include Unit 1 steam turbine vibration issue (as a result of a 2015 Mark V control and Lube oil system failure).

The study scope excluded significant consideration of:

- The Holyrood marine terminal
- Holyrood 120 MW CT
- Black Start Diesels

3. Methodology

The work was undertaken through a number of steps:

- Site visit
- Site review and equipment/facility walk about inspections
- Review the Holyrood Plant Maintenance Program - existing Information/background data, interview staff
- Review and analyse of recent information and data gained with respect to Holyrood through:
  - Existing studies on condition assessment, life expectancy, previous studies of life extension, and the associated costs (capital and O & M) of such programs
  - Physical inspection reports of equipment as previously noted
  - Interviews/discussions with Holyrood Operations and Maintenance and Management personnel
  - Preliminary assessment of the impact and value of capital upgrades and operational and maintenance improvements?

To the extent practical, the approach followed kept in consideration several 2010/11 and 2017 updated Condition Assessment aspects:

- Only design or overall service parameters are examined
- For conservative considerations, the residual life compared to the anticipated extended service period (or the interval to the next inspection whichever is less) hasn't changed except where extensive replacement or refurbishment work has been done
- Consider recent service and measurement information where practical, available and useful – including:
  - Unit running hours
  - Numbers of starts and stops – hot, warm, cold, trips, ramp rates
  - Unit load records
  - Failure history and analyses reports
  - Maintenance activities
  - Specifics of recent component repairs and replacements
  - Steam temperature histories
  - Design parameters

The Scope for this update as per the project proposal is limited to major changes since 2010/11 Condition Assessment report and the 2017 updated report, and primarily to 2010/11 and 2017 high priority items. It is an addendum report with limited charts and graphs, typically 8.5" x 11" pages.

- Generation fuel costs: $250+/MWh from new CT's vs about $130+/MWh from Holyrood units
- Assume full generation capacity/capability from Holyrood to March 31, 2023
- Unit 3 strictly synchronous condensing after 2023 (Revised to include Cold Standby/Emergency Generation to 2027+
- IRIS system in place and used on generators

4. Holyrood Asset Register

No changes are assumed or identified herein, even though through capital equipment changes some numbering may in fact have changed.

5. Holyrood Plant Maintenance Program Review

As input to the overall 2019 condition assessment update, Wood reviewed the Holyrood plant maintenance program through staff interviews. The primary factor was the effort being undertaken to maintain reliable, safe, economic operation in light of reducing demand for electricity generation, but with ever increasing criticality when it is needed.

5.1 Maintenance Strategy

The maintenance strategy presently in effect at Holyrood is basically being implemented through a combination of in-house resources for work performance and/or management, external resources for major equipment technical support, overhauls, and specialized services, as well as specialized short-term contractual arrangements with key retired or external staff through 2023, and in some manner to 2027 and beyond. The turbine generator contract expired in 2019, the boiler contract in 2020, and of the 30 service contracts, 6 have expired to date.

From Woods perspective, in most areas of the operation, the maintenance strategy and the asset management program at Holyrood are being implemented reasonably given the prospect of a March 2023 generation shutdown (and with possible cold standby/emergency generation to 2027+), and similar the case with other thermal generating stations in North America where shutdowns have been imminent.

5.2 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 continues to use multi-year maintenance contracts. Service contractors provide the majority of the boiler, turbine and generator maintenance, including major and/or minor overhauls, and have had on site technical directors on site ensuring that Holyrood's needs are met.

As noted, the plant also continues to have numerous 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.

Especially given its circumstances, the use of contractors and external technical resources is most consistent with maintaining 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.

Currently many major equipment-based inspections, Overhauls, even PM's and CM's are time based. This has been entirely appropriate given its historically consistent operating pattern over the last twenty years or more. This is a key element of the maintenance strategy that would have to change in the post Muskrat era, particularly in the period post March 2021 as generation reduces and then in 2022 or 2023 if the station enters a cold standby/emergency generation mode and with Unit 3 used significantly operating as a synchronous condenser. Rather than a time-based approach, inspections and overhauls and refurbishments/replacements would be condition/equivalent operating hours based, with time based elements as an influencing factor.

5.3 Human Resources (Chapter 5.3 in 2011 and 2017 Reports; Chapter 15 in this report)

Holyrood TGS has experienced significant human resource challenges since it was originally announced that it would be substantially reduced in generation once Muskrat Falls came into service and on standby for two years thereafter.

Several measures have been taken, working with the Union, to minimize or mitigate some of the impacts. There have been experienced temporaries retained using premium rates through March 31, 2021. These are assumed to be extended until the end of steam operations (at least March 31, 2022) to March 31, 2023 for this study. Several senior and intermediate people have migrated to other roles from Holyrood Operations: for example, eleven people moved in 2017, including a shift supervisor. Even with replacements getting on boarded typically with three months overlap, this has left the station with a significant portion of junior staff and/or others less experienced within the Holyrood station specifically. This has had the potential to impact both safety and reliability and is the focus of considerable effort.

For standby years from March 2023 through 2027+ when operating in a cold standby/emergency capacity role, human resources will continue to play a key role. Wood and Holyrood management discussed this and have put together a preliminary plan for staffing. Personnel associated with the 120 MW Hydro GT and with other GT and diesel facilities have in 2020 been transferred to fall under a single thermal generation group.

- Maintain and expand premium temporary retention program to retain key staff through 2027+, including station management and administration (ensuring operating engineer and other regulatory requirements are maintained)
- Define critical stand-by staffing
- On-board and train more inexperienced staff in 2020-2023 while units are still in operational mode
- Develop a low operating factor training/skills maintenance program
- Develop an appropriate standby equipment and staff unit start-up exercise program
- Update current procedures and practices documentation
- Develop/optimize staff sharing/skill interchanges/familiarization programs with other facilities (Holyrood gas turbine; Soldier's Pond; new peaking facilities)
- Develop a multi-skill program (operator/maintainer)

Human Resource issues/concerns include risks associated with safety, environmental impacts, efficiency, and costs.

Details of Human Resources current and suggested are addressed in more detail in Chapter 15.

5.4 Capital Plan Review (Chapter 5 in 2011 and 2017 Reports; Also Chapter 13 in this report)

5.4.1 Capital Investments to 2019

Staff and management involved in capital improvements completed since 2010/11 and 2017 at Holyrood should be commended (i.e. replacing elements of 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 and reheater replacements, boiler economizer and airpreheater deep cleaning and repairs, the installation of a new boiler chemical injection system; generator overhauls/rotor rewinds; steam turbine overhauls). They have all contributed to increase the reliability and overall life of the plant.

A listing of significant capital improvements in the period 2015 to 2019 is presented in Table 5-1.

Table 5-1 - Holyrood 2015-2019 Capital Program

Capital Projects 2015 to 2019			
		2015	
129V & 258V Distribution panels and Breakers (Stage 2) Replacement	Upgrade Excitation Systems U1,U2	Powerhouse Roofing Upgrade	Quarry Brook Dam Equipment Upgrade
Fire Protection Upgrade (Outbuildings)	Fire Alarm Tie-In	Chemical Storage Building Floor and WWTP Dyke Upgrade	Fuel Oil Tank#1 Roof Access Plateform
		2016	
U3 Turbine Generator Major Overhaul	U3 Rotor Rewind and Reflux Probe Installation	Aux Steam and Heating Study	Tank #1 Extension Inspection
U2 Reheater Repair	U1 Reheater Repair	Purchase 12MW Diesel Generation	Boiler Tube Replacement U1,U2
Powerhouse Building Envelop (MY)			
		2017	
U2 Turbine Valve Overhaul	Overhaul U3 West CW Pump, U3 North CE Pump, U2 West BF Pump	Purchase Capital Spares	Condition Assessment and Misc Upgrades
Replace Exciter Controls	Reliability Upgrades	Road Upgrades	Underground Drainage Upgrades
Powerhouse Siding Replacement	Laboratory Vestibule and Walkway	Domestic Waterline Upgrade	New Valve and Blow Down Line
Tank # 2 API Internal Inspection			
		2018	
Thermal In-Service Failures	Overhaul U2 South Vacuum Pump, U2 East BF Pump	Condition Assessment and Misc Upgrades	Overhaul U1 Generator
Overhaul U1 Turbine Valves	Improve Boiler Capacity	Raw Water Line Installation	Outbuildings Fire Detection Upgrade
BCC Cooling Upgrade	H2S Monitoring Installation	Fire Suppression System Installation Day Tank	
		2019	
U3 Turbine Valve Overhaul	Condition Assessment and Misc Upgrades	Thermal In-Service Failures	U3 Generator Electrical Testing
Replace 258VDC Battery Banks	Powerhouse Building Vestibule	Tanks 3,4 Extension Study	Replace warehouse fencing and lighting upgrades
Replace front entrance walkway	Anti-Slip Mats in WWBB	Safety Rail Replacement (Pumphouse 1 and 2)	Public Safety Around Dams Work Additions HTGS

5.5 2019 Capital Plan Investments for March 2021 End of Steam Generation

Table 5.2 presents the 2019 capital plan which at the time assumed an end of steam date of March 31, 2021. This plan does not include recent supplemental projects that HRD TGS believe are needed to be done in order to have the normal operating period extended beyond March 31, 2021 to March 2023. Note: It also does not include boiler overhauls, which are not capital.

Table 5-2 2019-2024 Capital Plan – For End of Steam Service March 2021

2019 HTGS Capital Plan (2020-2024)						
Year	Project	2020	2021	2022	2023	2024
2020	Rewind Unit 3 Generator Stator	1,359.6	5,789.0			
	Upgrade UPS 3 & 4	266.7				
	Install Plant Heating System (Will be SUPPLEMENTAL)	519.1	6,953.7			
	Upgrade Waste Water Basin Building (Submit for 2021 or SUPPLEMENTAL)	116.7	1,362.7			
	Thermal In Service Failures	1,250.0				
2021	Replace One of North or South Instrument Air Receiver Systems Unit 3		753.0			
	Inspect and Overhaul Stacks		500.0			
	Upgrade Property Fencing		50.0	50.0		
	Replace Stage II Electrical Distribution Equipment		2,513.2	2,269.6		
	Upgrade DCS Controllers / Hardware		250.0	250.0		
	Water Treatment Plant - Acid/Caustic Tank Upgrades		200.0			
	Replace One of North or South Service Air Receivers Unit 3		308.0			
	Thermal In Service Failures		1,250.0			
2022	Upgrade On-Site & Access Roads			500.0		
	Refurbish Biogreen Waste System			100.0		
	Fire System Upgrades			275.0		
	Thermal In Service Failures			1,250.0		
	Light Oil System Inspection and Upgrade			100.0	900.0	
	Install New Lube Oil / Seal Oil Systems Unit 3 (Inc. Assessment of LO Program)			255.0	765.9	
	Overhaul Unit 3 - Generator Only			1,300.0		
	Upgrade 600V VFDs in Wastewater Treatment Plant			250.0		
	Replace existing Stage 1 4160 V AC Breakers as Required			750.0		
	Install Energy Efficient High Bay Lighting System			15.9	609.2	
	Units 3 Generator Upgrades - Slip Rings, Brush Gear, Bearings, Pony Motor and Starter, SSS Clutch, etc..			941.5	784.6	1,273.9
	Upgrade Protective Relaying - Unit 3 Generator (SEL)			500.0		
2023	Cooling Water Pumphouse Refurbishment (stop logs in yr.1, new removable screens, 60 hp pump/motor, Insp. CW				650.0	400.0
2024	Upgrade Ambient Monitoring Stations					250.0
	Water Treatment Plant Upgrades (if required for GSCW, Domestic)					1,000.0
		3,512.1	19,929.6	8,807.0	3,709.7	2,923.9
		2020 TOTAL	2021 TOTAL	2022 TOTAL	2023 TOTAL	2024 TOTAL

Most of these are for Stage 2/Unit 3 facilities or common facilities and Wood concur that they will be required for ongoing Unit 3 synchronous condensing operation.

5.5.1 Capital Plans and Supplemental Capital for March 2023 End of Normal Steam Generation

There is no question that Holyrood would continue to need capital improvements, including some dedicated to the generation/steam side of the plant which, under the terms of this study, need primarily to address the time up until the expected end of generation period of March 2023.

Refer to Chapter 13 "Summary Capital Plan Assessment and Suggestions" for this period.

5.6 Maintenance Review Conclusions

NL Hydro certainly appears committed to meeting their regulatory, insurance, and safety requirements through ongoing inspections, maintenance, fire safety, and capital programs. Holyrood continues to transition to new PM programs and limited capital and OMA expenses.

Clearly to extend normal operations beyond the current March 31, 2021 date to March 31, 2023 and also in a cold standby/emergency mode beyond March 2023 will require additional supplemental maintenance and capital investments. The safe extensions of API out of service internal inspections of Tanks 1, 2, 3, and 4 are critical major cost elements for which NLH needs clarity from the Government asap.

6. Holyrood Operating History and Future Assumptions

Assuming that the necessary capital works planned for 2019 through March 2023 are completed, the units/station is considered technically well positioned to continue operation, at least on a reduced generation level to 2023 and in a cold standby/emergency mode to 2027 or beyond such as is contemplated.

Figure 6-1 - Holyrood Units One & Two and Three Generation/Operation Forecasts

	Unit 1						Unit 2						Unit 3								
Year	Annual Capacity Factor	MWh/Yr	Operating Factor %	Starts Per Year	Gen OP Hrs/Yr	Generation OP Hrs Cumulative Base	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Gen OP Hrs/Yr	Generation OP Hrs Cumulative Base	ACF	MWh/Yr	Operating Factor %	Starts Per Year	Gen OP Hrs/Yr	Generation OP Hrs Cumulative Base	Synch Cond Hrs Per Year	Synch Cond OP Hrs Cum	Synch Cond + Gen OP Hrs Cum
2016	40.4%	618,820	77.74%	9	6,828	200,798	33.51%	513,660	65.09%	14	5,700	192,393	37.48%	574,640	60.74%	8	5,336	153,586	0	48,230	201,816
2017	39.7%	608,610	70.22%	15	6,151	206,949	34.89%	534,810	59.42%	13	5,205	197,598	47.7%	626,540	72.48%	8	6,382	159,968	0	48,230	208,198
2018	24.7%	379,000	51.75%	14	4,533	211,482	30.71%	470,790	57.4%	14	5,025	202,623	22.4%	294,260	34.35%	7	3,009	162,977	2,758	50,988	213,965
2019	26.1%	333,690	53.2%	7	3,882	215,364	30.34%	387,320	54.7%	6	3,988	206,549	25.5%	279,230	37.63%	6	2,737	165,714	1,948	52,936	218,649
2020	20.0%	306,600	34.0%	8	2,978	218,342	20.0%	306,600	34.0%	8	2,978	209,527	20.0%	306,600	34.0%	4	2,978	168,692	2,000	54,936	223,628
2021	20.0%	306,600	34.0%	8	2,978	221,321	20.0%	306,600	34.0%	8	2,978	212,506	20.0%	306,600	34.0%	4	2,978	171,670	3,000	57,936	229,606
2022	10.0%	153,300	18.0%	8	1,577	222,898	10.0%	153,300	18.0%	8	1,577	214,083	12.2%	187,026	20.0%	3	1,752	173,422	3,000	60,936	234,358
2023	5.2%	79,716	14.0%	6	1,226	224,124	5.2%	79,716	14.0%	6	1,226	215,309	4.4%	67,452	8.0%	3	701	174,123	3,500	64,436	238,559
2024	0.9%	14,400	4.4%	5	384	224,508	0.9%	14,400	4.4%	5	384	215,693	0.9%	14,400	4.4%	3	384	174,507	4,000	68,436	242,943
2025	4.8%	73,200	8.2%	5	720	225,228	4.8%	73,200	8.2%	5	720	216,413	4.9%	75,600	8.2%	3	720	175,227	4,000	72,436	247,663
2026	0.9%	14,400	4.4%	4	384	225,612	0.9%	14,400	4.4%	4	384	216,797	0.9%	14,400	4.4%	3	384	175,611	4,000	76,436	252,047
2027	0.9%	14,400	4.4%	4	384	225,996	0.9%	14,400	4.4%	4	384	217,181	0.9%	14,400	4.4%	3	384	175,995	4,000	80,436	256,431
2028	4.8%	73,200	8.2%	4	720	226,716	4.8%	73,200	8.2%	4	720	217,901	4.9%	75,600	8.2%	3	720	176,715	4,000	84,436	261,151
2029	0.9%	14,400	4.4%	4	384	227,100	0.9%	14,400	4.4%	4	384	218,285	0.9%	14,400	4.4%	3	384	177,099	4,000	88,436	265,535
2030	0.9%	14,400	4.4%	4	384	227,484	0.9%	14,400	4.4%	4	384	218,669	0.9%	14,400	4.4%	3	384	177,483	4,000	92,436	269,919
2031	4.8%	73,200	8.2%	4	720	228,204	4.8%	73,200	8.2%	4	720	219,389	4.9%	75,600	8.2%	3	720	178,203	4,000	96,436	274,639

Notes:

1. Green values are actual values for period to end Mar 31, 2019 (estimated in Nov 2019 for 2019).
2. Yellow values are predicted, based on all Holyrood units running at reduced levels, but maintaining hot standby capability to Mar 31, 2023.
3. Blue values based on cold standby/emergency operation – 2 days at 150MW 2 times/year, plus 2 to 4 weeks at 175 MW once every third year.
4. Unit 3 operate more as Sync Cond. (May also provide aux steam 2021+ for building/fuel heating, faster warmup/start. Boiler ops hours higher than shown.)

7. Overall Plant Condition Assessment

Holyrood is still considered to be a relatively modern design steam cycle power plant and in fair to good condition for its age, although much of its equipment and systems are of course of an older generation and some parts are considered obsolete by today's standards.

In principle the 2019 HRD TGS Condition Assessment Update reflects the fact that Holyrood Units 1 through 3 were installed in 1969, 1970 and 1979 respectively. They are as of 2019 therefore about 50, 49, and 40 years old, and thus past the conventional calendar benchmark for financial (often technical) end of life of 40 years and would in some cases already have been retired/decommissioned. It is also true that the units have passed or are close to 200,000 hours of operation which is another benchmark for technical end of life/major refurbishment timing. There have been many operating units in North America that would have however exceeded these guidelines in the past.

Nevertheless, there has been considerable work on refurbishing and/or replacing key elements that were identified in 2010/11 and 2017 as high risk and were causing reliability issues in 2014-2016. Also, it has to be recognized that that the units have not been overly stressed – they have not been two-shifted; their start-up and shutdown timeframes have been less stressful; and load cycling has been modest typically between 50% MCR and about 90% MCR. The units were also upgraded in the 1980's to 175 MW from 150. Much of the major equipment has been significantly upgraded and extensively condition assessed.

Most major and high risk issues identified in the 2010 extensive Condition Assessment and the 2017 Condition Assessment Update have been addressed and rectified. The major equipment issues remaining are primarily related to continued reliable boiler operation (related primarily to the fact that it is heavy oil fueled). Others include Unit 1 steam turbine vibration issue (as a result of a 2014 Mark V control and Lube oil system failure).

Holyrood units are expected to be able to meet both a March 2023 end of normal steam generation and likely a March 2027+ date for the end of its electricity generation cold standby/emergency role with the planned capital refurbishments and replacements, primarily required 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 ongoing boiler inspections and repairs, ongoing steam turbine generator overhauls, site firewater system repairs, breaker and motor control centre refurbishments, waste water treatment basin building structure repairs, building heating and ventilation system implementation, plant elevator refurbishment, and equipment such as vacuum pumps. In the post steam period, the timing of much of the work would switch from a calendar based system to a Condition/equivalent operating hours basis (with some consideration given to calendar timing).

Holyrood Unit 3 is also expected to be able to meet a 2043 synchronous condenser end of life but will require some further significant generator and auxiliaries equipment refurbishments and replacements specific to that role that are identified later in the report. Examples of these over time would include a generator stator rewind (Note: rotor rewind completed in 2016 and stator rewind approved for 2020/21 completion), and some switchyard breakers and motorized switches and synchronous condensing equipment refurbishments.

Fossil plants of a similar era as Holyrood were typically designed with a nominal economic life of 30 years, although 40 years was considered a more typical technical life. For practical purposes, this meant at least a 40 year technical life. However, some fossil plants in the United States were still in active service and quite functional at over 60 years of age, until flue gas desulphurization (FGD) and selective catalytic reduction (SCR) retrofit requirements for sulphur dioxide (SO^2) and nitrogen oxides (NOx) reductions made them uneconomic.

While Holyrood Units 1, 2, and 3 were approximately 50, 49, and 40 years of age in 2019, their historical seasonal based, light to moderate load service would suggest that the operational age for the majority of its equipment and systems is more like 30, 30, and 25 years respectively. The plant has generally 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.

Boiler and Auxiliaries

The boiler and its major elements are 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 significantly improved boiler reliability and efficiency and has had a positive impact on the life of boiler systems. Changes in fuel supplier in 2015 led to use of higher silica, higher alumina oil that also had tendencies to separate into layers and deposit solids layers in tanks. This resulted in significant handling system failures and costs in 2015. Although somewhat addressed through changes in fuel specifications in 2016, fuel can likely still be an issue where long periods of storage are likely.

The boilers undergo regular boiler regulatory and condition assessment/repair inspections/overhauls. Many issues have been found since the major 2010 assessment and repaired. Details of inspections are included in the boiler sections of Chapters 8 through 10.

Based on the history of many years of boiler inspection and repair, there is no reason why the plant boilers cannot continue, with appropriate inspections and repair work, to generate electricity reliably to March 2023 and in cold standby/emergency mode to 2027+. There remain however pre-requisites to this, including continued and enhanced inspection and maintenance programs, and planned major equipment refurbishments.

Generators and Major Electrical Equipment

One key to successfully managing plant life has been various inspections and tests and refurbishments of generators, transformers, and switchgear. Units 1 and 2 have had major generator inspections and testing that have indicated that these units are good to reach March 2021 (and by our assessment to March 2023) without any further rewinds (subject to ongoing regular testing/monitoring). No testing indications suggest that they cannot likely achieve normal operation to 2023, and in cold standby/emergency operations to 2027+. Unit 3 was overhauled in 2016 and had its rotor rewound (for synchronous condensing to 2043 this was warranted). Unit 3 is also planned to have a stator rewind in 2020 or 2021 for long term reliability purposes. Unit 3 generator rewinds, controls and alarms upgrades/spares, and switchgear upgrades/replacements and breaker planned maintenance/refurbishments/spares are key elements for it to achieve the targets for 2023 and 2027 and 2043.

Transformers and Switchgear

Transformers are at the point in their lifecycle where significant degradation also occurs. More frequent spot monitoring and continuous gas condition monitoring are in place to manage their life through 2023 and for Unit 3 beyond.

Existing switchgear is in many cases at or near end of life, but planned maintenance incorporating selective refurbishment and replacement particularly for Unit 3 and maintenance of sufficient spares should manage life to March 2023 and in cold standby/emergency mode to 2027+ and for Unit 3 as synchronous condenser to 2043.

Other Issues

Other significant issues in 2010/11 and 2017 involving single contingency systems have been or are being addressed and include:

- The single contingency failure risk of the fresh/raw water supply from Quarry Brook Pond (Quarry Brook Dam Equipment Upgrade was upgraded in 2015; 2nd raw water line added in 2018);
- The single contingency failure risk of the clarifier failure, at least until 2023; and on standby emergency mode to 2027+.
- The 42-year age and condition of the black start gas turbine – replacement with the six 2 MW diesel generators and installation of the 120 MW simple cycle gas turbine at Holyrood site.
- Critical spares stockpiling (Mark V cards, breaker parts, etc.) and OEM special support agreements have helped address age related reliability issues and parts obsolescence

There are several significant issues that have arisen since 2011 and 2017 that are in the process of being assessed and addressed as required, such as:

- Site fire water piping condition – recent sections have failed and been repaired
- Cooling Water intake and outfall sumps and piping
- Fuel tank regulatory inspection timing – delaying out of service inspections
  - Tank 1 and 2 out of service inspections - delayed Regulatory required inspections approval granted to no later than Dec 2021, but Tank 2 likely good to 2027
  - Tank 3 current approval without major inspection expires in 2022, but condition assessment study indicates its out of service internal inspection could be significantly extended to 2033
  - Tank 4 current approval without major inspection expires in 2020, but condition assessment study indicates its out of service internal inspection could be significantly extended to 2027
- Marine terminal fender and piling condition
- Condenser waterbox wall thickness conditions

Overall, as Hydro has addressed the key issues and incorporated a more rigorous maintenance and inspection program, there is no identified technical reason with appropriate continued maintenance that the plant cannot make its March 2023 generation end of normal steam operation life and 2027 cold standby /emergency mode to 2027+and Unit 3 2043 synchronous condensing end of life targets.

7.1 Issues for Continued Cold Standby/Emergency Mode Operation Beyond March 2023

Wood consider several issues to be significant for the continued use of Holyrood Units 1 and 2 (i.e. as a feasible option for supplying 300 MW of Avalon standby emergency capacity (or even for partial supply), as well as Unit 3, beyond 2023 including:

1. Human Resources - how to staff for ops, for mtce; for permitting as required
2. Quick Start Up and Shutdown – 12 hr and 24 hr
3. Boiler Equipment Life/Reliability Issues
   a. Boiler issues with infrequent ops,
   b. Periodic operation for equipment exercising/checking and for operator readiness.
4. Fuel Supply and Management – the number of fuel tanks to maintain/inspect; maintaining fuel quality with long term storage; fuel recirculation and heating; fuel settling/desegregation; fuel delivery arrangements - quantity, timing, quality
5. Steam Turbine and Generator Reliability
6. Water - Demin water supply and storage; fire water system; WTP condition
7. Civil structures
8. Ongoing Condition Assessments

7.1.1 Human Resources

For 2023 through 2027+, even though operating in a cold standby/emergency capacity role, human resources will continue to play a key role:

- Maintain and expand premium temporary retention program to retain key staff through 2023, including station management and administration (ensuring operating engineer and other regulatory requirements are maintained)
- Define critical stand-by staffing
- On-board and train more inexperienced staff in 2020-2023 while units are still in operational mode
- Develop a low operating factor training/skills maintenance program
- Develop an appropriate standby equipment and staff unit start-up exercise program
- Update current procedures and practices documentation
- Develop/optimize staff sharing/skill interchanges/familiarization programs with other facilities (Holyrood gas turbine; Soldier's Pond; new peaking facilities)
- Develop a multi-skill program (operator/maintainer)

7.1.2 Quick Start Up and Shutdown

Holyrood could certainly play an emergency role for expected potential emergency situations where bad weather was expected and plans for Holyrood start-up could be orderly and slow, well in advance, it could not respond as quickly as desired as it is currently operated and configured in a cold standby mode in the event of an unforeseen outage (which by their nature are likely few and far between).

The plant is limited by several factors:

- An internal expectation by operators and NLSO that the start-up is always 2 to 3 days from cold (during discussions it was suggested that one recent test had shown 8-12 hours likely possible). This is primarily the result that there was no real driver in past to change and justify any associated real or perceived risk.
- the limited availability of auxiliary steam capability in cold standby as configured for oil fuel heating and boiler/steam turbine preheating

Wood believes that the Holyrood can provide much faster start-ups than historically implemented (and lower minimum loads) both for hot standby purposes in the period up to its end of generation life (March 2023), as well as in the cold standby/emergency generation period from March 2023 to 2027+. It will require some changes in mindsets with both NLSO and HRD, requiring a more aggressive approach. It will require a series of tests to prove fast start capability and reliability, as well as also require some improvements in some systems – fuel, boiler, steam turbines, controls, and simulator. It is likely that the criticality of fast start ups during the non-winter readiness period to March 2023 is less significant. It is critical that the testing and the necessary changes (See Chapter 16) be made in the 2020 and 2021, either way is likely to involve some significant incremental capital and operating costs:

7.1.3 Boiler Equipment Life/ Reliability Issues

The schedule for overhauls and planned overhauls (Minor and Major) are illustrated in the Figure below.

Boiler Overhaul Schedule

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unit #1	Ma	Mn	Ma	*	Ma	Mn	Mn	Ma	Mn	Ma	Ma	Mn	Mn	
Unit #2	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma	Mn	
Unit #3	Ma	Ma	Mn	Ma	Mn	Ma	Mn	Mn	Ma	Ma	Mn	Ma	Mn	

Ma **Major**
Mn **Minor** ***No Boiler Overhaul for U1 in 2013**

The B&W Boiler 2018 Condition Assessment Report assumed an end of 2021 shut down date. It concluded that Level 2 Condition Assessments of the boilers were not justified. It did indicate that in addition to the normal inspection protocols during shutdowns that some additional inspections be carried out, particularly where wall thinning/FAC were identified and where borehole ligament cracking has been observed, as well as integrity of hangers/supports. Recommended inspections would be based on previous year's inspections.

In 2019 and beyond, the concept of "Recommended inspections based on previous inspections" has and should be continued as long as the unit is required for generation purposes. In February 2020, B&W issued their 2019 review of inspection findings and comments on extending boiler normal operating life to 2029. It indicated a few key items for investigation in 2020:

- Unit 3 RH Leading Edge Bends – bends not pad welded yet should be
- Unit 3 water wall Tubes around burner openings – measure wall thickness by UT of tubes not pad welded and pad weld those with wall thickness <0.148"
- Tube to Header Welds – any cracks should be excavated, and weld repaired
- Piping FAC – pad weld any piping locations evaluated for FAC if wall thickness <ASME minimum
- Boiler Tubing – any boiler tubing evaluated and has wall thickness <B&W PSB-26 recommended value should be replaced

A complete set of B&W's 2019 Recommended Future Inspections is presented in the boiler section of each unit in Chapters 8, 9, and 10 respectively.

Many of Holyrood's boiler issues can be traced back to the original high sulphur (2.5%S+), high vanadium, "dirty" residual oil fuel, and to issues with fuel quality in 2015, resulting in significant downtime and unreliability. In 2019 sludge deposition in unit fuel filters and heaters also occurred, primarily due to separation of the fuel in main and day tanks. An advanced cleaning technique was employed to clean the unit filter/heater equipment at a significant cost and is likely going to required going forward as it may become more pronounced when the station enters a cold standby/emergency mode where fuel sits in storage for extended periods. Some form of heating and/or recirculation may be needed.

Boiler FD fan systems (Units 1 and 2 in particular) have also historically had issues with fan /duct vibration, and air preheater/economizer pluggages. Aggressive economizer and airpreheater cleaning in 2017 through 2019 and operational changes helped maintain unit capability. Some fan internal inspections in 2020 are expected to be required in this area for the 2020 to 2023 period.

7.1.4 Fuel Supply and Management

7.1.4.1 Main Oil Tanks

The existing tank farm consists of four 33,710 m3 (212,000 bbls) tanks. Each holds a fuel oil having 6.5 MMBTU/bbl, HFO cut with diesel fuel. Historically, fuel has been delivered about every 3 weeks. The preferred plan would be to have 4 tanks to 2023 (although an analysis and decision on Tank #1 refurbishment is needed), and possibly fewer during the period of cold standby/emergency through 2027+.

At issue is that:

- Tank 1 had a 2019 in-service visual inspection. Its 2019 out of service inspections was delayed, and approval granted to no later than Dec 2021. December 2021 is also the date its condition assessment identified as end of service life without substantial repair and internal API inspection. It requires significant expenditure to extend its life.
- Tank 2 had an API 653 In-Service 2017 inspection. Its 2018 out of service inspections was delayed, and approval granted to no later than Dec 2021. The most recent tank inspection report indicated that it is in much better condition than Tank #1 and that an inspection deferral (if approved by Regulators) to 2025, possibly 2027 would be reasonable (2027 also identified as end of service life without likely repairs). No response to the request has been received as yet.
- Tank 3 had its last API In-Service inspection in 2012. Its current approval without major out of service inspection expires in 2022. A condition assessment report was completed in 2019 that is the basis for a submitted regulatory inspection deferral to 2027, or as late as 2033 (2033 also identified as end of service life without likely repairs) No response to the request has been received as yet.
- Tank 4 had its last API In-Service inspection in 2010. Its current approval without major out of service inspection expires in 2020. A condition assessment report was completed in 2019 that is the basis for a submitted regulatory inspection deferral to 2027 (2027 also identified as end of service life without likely repairs).No response to the request has been received as yet.

The average API out service inspection per tank is about $3.5 million without roof repairs and about $5 million including roof repairs. It is expected that all API inspections will be deferred where possible to after 2023 where possible, including next day tank O/S inspection

Each tank has a functioning steam suction heater for temperature control of the oil discharge, but their two immersion platform heaters in the tank itself are non-functional. There is no internal mixing or stirring or recycle. Steam from the auxiliary steam system provides the thermal input. Condensate is discharge via steam traps to drains. A 16" radial pipe to the 18" main supply header takes the oil from the tank farm by gravity flow to the Day Tank.

The current plan is to maintain the active size of the main tank farm for normal use to March 2023. It is expected that the amount of main fuel required after March 2023 for the exercising of the units (each unit twice per year for 2 days at 70 to 150 MW) would be between 50,000 and 75,000 bbls. Full station emergency use at any time after March 2023 for 3 weeks (3 units x 150 MW to 170 MW x 3 weeks) is about 360,000 to 400,000 bbls. Each would also require #2 oil for start-up/warm-up. For cold standby with one unit acting as an auxiliary steam supply, additional main and light oil would be needed, at least during the winter readiness period. A functioning suction heater plus main tank recirculation may be desirable going forward.

7.1.4.2 Day Tank

The heavy oil day tank was replaced with the addition of Unit 3. The tank provides gravity flow to the supply pumps on each of the individual units. Unit 3 has a maximum 10.08Kg/s (80,000 Lb/hr) requirement for example supplied by 2 x 100% positive displacement pumps through 2 x 100% fuel oil steam heaters providing 99°C (210°F) oil to the units. There is a bypass around the day tank from the main tank farm, if required.

The Holyrood boilers were designed to incorporate a light oil system for use in lighting off the steam generators from a black start when atomizing steam is not available for firing with #6 oil. However, this system has not been used and the equipment to do this is not provided. The idea was that the light oil is fired in the bottom level of burners. The light oil is provided from the station light oil tanks via a header to unit light oil pumps. Atomizing air is provided via the unit Service Air system for the fuel and for purging on burner shutdown. There are two x 100% positive displacement pumps providing about 1034 kPa (150 psig). There is a recirculation system back to the tanks from the burner front header.

The day tank appears in fairly good condition. Its common header was cleaned/refurbished in 2013 and the tank cleaned out after the 2015 poor fuel incident.

In 2019 there appears to be some significant deposition in the day tank resulting from the fuel make up and long sitting times. This has resulted in some pluggage of unit fuel filters and heaters. For the cold standby period and for fast starts, it may be necessary to install some active recycle back to the day tank through a recycle pump and auxiliary heater of some sort.

There was a 2017 visual inspection completed. The next API out service inspection would be scheduled for 2023, possibly deferred to sometime in the 2023 to 2027 period. The costs could be on the order of $500,000.

7.1.4.3 Marine Terminal Condition

The marine terminal Jetty had its annual PM in 2017 including a pile inspection and anode replacement. Essentially it was intended to provide for a 10-year life extension to 2027. In 2018, Boland Marine and Industrial refurbished the north and south 12" MLRA Loading arms. A 4' line with 2" breakaway arms has been modified. Its expected life assessment is to beyond 2023, to 2027 or more. No additional costs have been identified against the jetty.

Additional inspections of the gravity fenders and concrete pile joints were initially considered for 2020, but within the period 2023 to 2027 may be warranted. The heat tracing system from the jetty to the main oil tanks has been an issue over the last ten to fifteen years. It is expected that any additional costs will be addressed by the allowance for production costs.

7.1.5 Steam Turbine and Generator Reliability

7.1.5.1 Steam Turbines

The Unit 1 and Unit 2 Steam Turbines are in reasonably good condition for their age, although Unit 1 has and continues to have a vibration issue resulting from the effects of a sudden shutdown in 2014 that occurred in combination with a Mark V control system failure and lube oil system failure. Although refurbished, it still requires more time and care in start up to avoid vibration trips. The turbines should readily be reliably functional to March 2023.

A turbine and valve overhaul scheduled as part of the proposed 2023 supplemental funding is warranted, but future inspections and overhauls are likely less frequent to 2027 and beyond. While no overhauls would be planned in this period given their relatively minimal use, consideration may be given to one in the event of an extended run or the identification of a currently unexpected issue.

T Turbine
G Generator
V Turbine Control Valves

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Unit #1			T/G/V			V			G/V			T/V			G/V			V			T/G/V
Unit #2		V			T/G/V			V			G/V			T/V			G/V			V	
Unit #3	V			V			T/G/V			V			G/V			T/V			G/V		

In 2017 Generator O/H seperated from turbine and changed to 6 yr cycle

The figure above illustrates the steam turbine, generator and valves overhauls between 2010 and 2030 that would have occurred under the current overhaul periods if the plant continued to operate. For Unit 1, 2, and 3 valve overhauls are typically planned for 2021, 2020, and 2019 respectively. Similarly Units 1, 2 and 3 steam turbine overhauls are typically expected in 2021, 2023 (major), and 2021. Generator specific major overhaul in 2024 (last one 2018). Beyond March 2023 while in cold standby/emergency mode, valve overhauls are likely extended to every 6 years, steam turbine overhauls at least every 10 years, and major generator specific overhauls to at least 10 years.

The Mark V controls continue to be an issue and are not scheduled for replacement before 2023, or in standby emergency use to 2027. An OEM support agreement has been in place and is expected to be extended. Additional spare cards and parts are also being accumulated. For limited operation to 2027, the approach is less clear. The card supply may be adequate but maintaining OEM support may require a more comprehensive agreement. Maintaining an In-house specialist would be difficult to justify. An allowance of $1 million/year to accommodate an OEM agreement during this period is likely warranted.

7.1.5.2 Generator and Auxiliaries

Unit 2 generator was refurbished in 2014 and electrical testing undertaken in 2017 (Stator - insulation resistance; Polarization index; DLRO winding resistance; DC leakage; Power Factor Tip Up; Rotor - insulation resistance; Polarization index; DLRO winding resistance; AC impedance; RSO test at rest). Unit 1 was overhauled/inspected and refurbished in 2012/13 and generator testing/inspection last completed in 2018.

Units 1, 2, and 3 generator specific major overhaul are typically expected in 2024 (last one 2018), 2020, and 2022 (stator rewind also in 2021/22). Beyond March 2023 while in cold standby/emergency mode, major generator specific overhauls should likely be considered every 10 years (6 years for Unit 3 while in synchronous condensing duty.

Generators of Units 1 and 2 are considered to be in reasonable condition, able to achieve a 2023 end of normal life and in standby emergency duty to 2027+ without rewinds. It is generally felt that life to 2031 is also achievable given the limited operation likely. Ongoing electrical monitoring and periodic ten-year generator testing and minor repair is warranted.

The Unit 1 and Unit 2 exciters have been upgraded in 2017. It is expected that they will make their 2023 normal life end date, and with moderate further upgrades if required also be able to make a 2027 date with limited standby emergency operation. A further allowance is suggested for testing and repairs/upgrades during the midpoint of 2023 to 2027 period.

7.1.6 Water Supply and Water Treatment Plant

The main raw supply pond dam is regularly inspected and considered in good condition. It will continue to be the source of fresh water for the plant and the gas turbine facility CT (for water injection and general use) so inspections and any repairs would likely be addressed as part of ongoing operations in future. No additional costs for incremental inspections or repairs are considered attributable to standby operation in 2023 to 2027.

The raw water supply line from the pond to the plant line will be required going forward for the plant and the gas turbine. The new raw water line was completed in 2018 and will ensure continued reliable plant supply. No additional costs for incremental inspections or repairs are considered attributable to standby operation in 2023 to 2027.

The fire water lines are fed from the pond to the pumphouse and then throughout the site in asbestos concrete pipes (except where replaced by PVC in repaired sections). The concrete pipe has failed several times in recent years and some sections should be assessed and replaced on an as-required basis.

The plant demineralized water supply and storage facilities will be required and in 2018 was repaired and run for the gas turbine, with some additional facilities being considered. The water treatment process should continue to be monitored and improvements/repairs made as required even in a standby mode.

7.1.7 Civil Structures

7.1.7.1 Stacks

Proposals for inspections and repairs of the #1, #2, and #3 chimneys were submitted by Industrial Chimney Maintenance Inc (ICM) in April 2016 (more extensive repairs and coatings) and February 2017 modest repairs and detailed inspection). Inspections were undertaken, but it was decided to defer the more expensive washdowns, coatings, and non-critical repairs.

For the units to be able to operate in normal mode through to March 2023 and then in standby/emergency mode 2027 beyond to March 2031, it is considered important that the more extensive stack work for Units 1 and 2 be completed, and that it is best that it be completed sometime between 2021 and 2024, preferably sooner rather than later. Regular regulatory inspections would also be maintained through the period. The current capital plan shows $500,000 in 2024 for inspection and repairs.

7.1.7.2 Seawater Condenser and Waterboxes

The seawater condenser (water boxes and steel pipes) are subject to seawater effects as well as the normal effects of water and age. The condenser inlet and discharge piping inspections were carried out on #1 in 2017 and for #2 in 2018. New steel pipes and coatings have been implemented. The internals of the water boxes were examined. The tube sheets are seen as being in reasonable shape and not an issue. The water box walls themselves have anodes in them but are considered to have relatively little material to enable weld to (UT testing). Overall, the equipment is considered suitable for modest service to 2027, although the integrity of the water boxes should be tested and continue to be monitored.

7.1.7.3 Screen/ Pumphouses #1 and #2

Screen/pumphouse #1 serves Units 1 and 2. The July 2017 sump assessment indicated a significant issue with the concrete floor. For reliable 2020 to 2023+ operation, some focused inspection and repairs are needed. Once addressed for normal operation to 2023, they should be suitable, but monitored for operation to 2027+. The screens/pumphouse structure should be suitable for continued emergency/standby operation.

Screen/pumphouse #2 serves Unit 3 and was designed for a future unit 4 (sump exists). The sumps and pipes are generally considered suitable for normal operation to 2023, and likely with some condition monitoring for operation to 2027+. The screens/pumphouse structure should be suitable for continued emergency/standby operation.

7.1.7.4 Continuous Blowdown Tanks

Two lines and later a third line in 2019 to clarifier which broke off were repaired as part of 2017-2020 capital.

7.1.7.5 Waste Water Basin Building

The Waste Water Basin Building is currently a restricted area, requiring special personal protective apparatus (breathing apparatus) due to the high mould concentration in the building due to its high humidity levels. The building also has significant, though somewhat superficial corrosion issues of steel members as well. It has been an on again, now off again capital project.

While it would be advantageous to address the issue for personal safety/health reasons, the current plan to continue to use a restricted access approach is not unreasonable to March 2023.

It would also be worthwhile to address the building issue for the 2023 to 2027 period, but as currently there is no more urgency than in current period to do more than restrict access until such time as another issue were to drive a physical change.

7.1.7.6 Powerhouse Building Roof and walls

A tremendous effort has been made and completed in 2017 on repairing/upgrading the main and primary powerhouse roves and walls, including asbestos abatement in wall panels.

Given the work to date, it is not expected that any significant additional remedial work will be required for the period 2023 to 2027. Periodic roof inspections will have to be carried out at perhaps a 2025 timeframe to verify continued integrity and identify any spot repairs likely required. This is probably within a $100,000 envelope.

7.1.8 Ongoing Condition Assessments

Condition Assessments were done in 2017 (equipment specific) through 2019. The capital plans since 2010 have been consistent with the various findings of assessment findings. The plant has as a result been well positioned the plant to continue to operate through its current March 2023 normal operation end (with continued investment and human resource plans). It is likely also capable to continue to operate in a limited emergency capacity role through 2027+ if deemed appropriate – with focused condition assessments, particularly as it pertains to the boiler and generator and auxiliaries undertaken at some points through the 2023 to 2027+ period to verify continued safe and reliable operation.

8. Unit 1

8.1 Unit 1 – Key Systems

8.1.1 Asset 6696 – 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
	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 2014. This as in 2017, 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_g (45 psig) pressure, 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 the hydrogen escaping from 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.

Since the original excitation equipment moved to its obsolete phase of its life cycle, the exciter in 2017 was partially upgraded. The power section and field breaker were reused, and the controls upgraded to Unitrols 6080 platform. 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.

Machine Type	Turbine-Generator	RPM	3600
Voltage / pf	16 kV / 0.9	Manufacturer	GE
KVA	194,445	Date Manufactured	1969
Insulation Class	B	Serial Number	980485
Cooling	Hydrogen @ 45 psig	Slots / Circuits	66 / 2

The stator core and winding are directly hydrogen cooled; the rotor has a directly hydrogen cooled winding, sub slot supply and radial discharge through the winding.

The auxiliary systems include:

- A static thyristor-controlled exciter fed from the generator terminals, with field flashing for initial energization; the controls were upgraded to the Unitrol 6080 platform in October 2017.
- 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; The PT's primary and secondary fuses are checked on the regular base. There is a spare PT on site in 2019, CT's are in good condition and are checked every 6 months.
- 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 shutdown. It uses two proximity probes at 45° to the vertical to measure the shaft vibration level: and
- A digital multi-functional generator protection relay at present is primarily used for extra ground fault protection of the stator windings. It also provides supplementary alarms and sequence-of-events monitoring. Bently Nevada upgrades were completed on all units.

8.1.1.2 History

No major change since 2010/11 Report and 2017 update. A failure occurred January 11, 2013 and a possible negative sequence event occurred in January 2014. A generator and steam turbine valve overhaul were undertaken in 2018.

8.1.1.3 Inspection and Repair History

In 2016 the excitation transformer was replaced, and the lead of the excitation transformer was changed to flexible lead. In October 2017, the exciter controls were upgraded to a Unitrol 6080 platform.

In 2018 (U1 Generator Outage Report Jul-Oct 2018), there was performed a major inspection.

The planned scope of the outage was as below:

1. Collector Disassembly, Clean and Inspection, Reassembly
2. LP-Gen Coupling Disassembly, Clean and Inspection, Reassembly
3. T4 Bearing Disassembly, Clean and Inspection, Reassembly
4. T5 Bearing Disassembly, Clean and Inspection, Reassembly
5. TE H2 Seal Disassembly, Clean and Inspection, Reassembly
6. CE H2 Seal Disassembly, Clean and Inspection, Reassembly
7. TE End Shield Disassembly, Clean and Inspection, Reassembly
8. CE End Shield Disassembly, Clean and Inspection, Reassembly
9. Rotor/Field Mechanical Inspection
10. Stator Mechanical Inspection
11. H2 Cooler Disassembly, Clean and Inspection, Reassembly
12. Generator Air Test

Extra Work Scope included:

1. H2 Cooler Steam Clean
2. Lube Oil Finish
3. Generator Belly Pan Inspection

The generator rotor/field were also removed, and electrical testing performed on both the stator and rotor:

Both stator and rotor from August 27, 2018 to September 09, 2018. The generator is a 175 MVA, hydrogen cooled with line-to-line voltage of 16 kV.

The scope of electrical work on the generator included the following:

- Stator

1. Insulation resistance (5000 VDC) test on each phase
2. Polarization index (5000 VDC) test on each phase
3. DLRO (winding resistance test)
4. DC leakage test
5. RTD resistance check
6. EL CID test
7. Wedge Tightness test
8. Tip-up (TAN Delta) test
9. Stator core and endwinding visual inspection

- Rotor

1. Insulation resistance (500 VDC) test
2. Polarization index (500 VDC) test
3. DLRO (winding resistance test)
4. AC Impedance test
5. RSO Test – at rest
6. Rotor bore leak check
7. Field visual and borescope Inspection

8. Retaining Ring Inspection (Ultrasonic and Eddy Current Inspection)

T Turbine
G Generator
V Turbine Control Valves

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Unit #1			T/G/V			V			G/V			T/V			G/V			V			T/G/V
Unit #2		V			T/G/V			V			G/V			T/V			G/V			V	
Unit #3	V			V			T/G/V			V			G/V			T/V			G/V		

In 2017 Generator O/H seperated from turbine and changed to 6 yr cycle

8.1.1.4 Condition Assessment

The generator is scheduled to operate in normal mode to March 2023, and in emergency/cold standby mode to 2027+. The generator has accumulated roughly 200,000 hours of service life and about 550 starts in 50 years of operation. In recent times, Unit 1 runs about 50 percent of the time and generally well below name plate rating. Operating at lower load reduces the temperature effects of aging on the rotor and stator winding insulation.

In 2013 and 2014, Alstom were on site for Unit 1 maintenance inspections and testing after the 2013 failure. They produced a report (#FSRG025890), which covers a comprehensive series of tests, visual inspections and maintenance of the stator and rotor. The testing consisted of; EL-CID stator core testing, stator winding wedge tap, insulation resistance, polarization index, high voltage dc ramp test, and a stator winding low voltage resistance test. All testing carried out in 2014 as well as 2018, indicated no immediate concerns. The visual inspection also did not find any significant degradation in the stator or rotor winding insulation. There was only some minor surface contamination and corona present in the end winding areas of the stator winding. Some dusting and greasing in the end-winding overhang area was also noted. A stator rewind was not deemed necessary at the time.

The rotor was visually inspected without the retaining rings removed in 2014, but in 2018 ultrasonic and eddy current testing was also conducted. No issues were identified that would interfere with continued operation. The assessment of the rotor condition identified no significant issues.

In late 2015 and early 2016, on-line stator winding Partial Discharge tests were carried out via the installed stator slot couplers (SSCs). The test results indicate only moderate to low levels of PD and did not give cause for any immediate concern for the stator winding.

Essentially the various assessments are that the generator shows aging signs typical for this type of GE generator. The rotor winding insulation is also still in reasonably good condition for its age. Overall, the generator is in reasonably good condition for its age, but regular inspections will still be required. Earlier it was considered to have a stator rewind in the 2021 to 2023 period, but this is unlikely to be economic or necessary.

The machine, both stator and rotor, have a high probability of making it to 2023 with only the normal maintenance. Beyond that, major refurbishments such as rewinds need only to be considered if significant usage during 2023 to 2027 or beyond period is to be considered. Once the unit enters its standby/emergency role, it is likely that major inspections would only be required every 10 years, subject to any extensive period of use or issues that arise during exercising operation or any online monitoring issues.

The generator exciter, and auxiliary systems are also in reasonably good condition for their age. Based on these changes and the testing/inspection results on the generator, there are no issues expected to limit the normal operation life before 2023 and limited standby/emergency operator to 2027 or beyond.

8.1.1.5 Actions

Given the most recent Overhaul and Testing information and results, the primary actions are continue the generator testing and inspections – probably in 2024/25 and thereafter every 20,000 equivalent operating hours (maximum every 10 years) of standby/emergency operation to verify condition (i.e. stator Doble test measurements; a pole-to-pole volt-drop or an RSO test on the rotor, for shorted turns, is recommended);

- Continue regular planned/predictive maintenance activities on various generator auxiliaries (hydrogen, oil systems, cooling systems, etc.)
- Monitor the stator 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.
- Check the hydrogen consumption and seal oil consumption for leakage (GE recommends seal oil supply piping flushed annually, to prevent dirt in the emergency by-pass line entering the system); last in 2018.
- Take stator Doble test measurements every 3 years of operation, during the summer outage (it is necessary to disconnect the neutral bar

No rewinds are required in the foreseeable future. No additional action is required related to retaining rings at this time given the remaining normal operating life.

8.1.1.6 Risk Assessment

By considering the high-risk elements of the Risk Assessment, Table 8-7 of the 2010/11 Condition Assessment report for the Unit 1 Generator and auxiliaries, it is clear that the high-risk issues for the generator and exciter have been dealt with.

Stator windings are generally of the most concern for long term reliable operation in the stator portion of the generator. Global deterioration of the Unit 1 stator winding insulation is not indicated from recent inspections and test reports. Future degradation cannot be reliably assessed, and the end of winding life cannot be predicted, especially if operating events are encountered. However, given the present condition of the stator winding, a stator rewind should not be required to the end of normal operation of 2023 or in emergency/standby mode to 2027. It is assumed that any gradual winding deterioration in normal service will be detected by condition monitoring and the condition restored by preventive and corrective maintenance. Normal monitoring, inspection, testing (i.e. on-line PD) and maintenance should allow operation out to normal operation of 2023 and in emergency/standby mode to 2027+.

The condition of the rotor also appears to be sound based on recent inspections and testing. The rotor does not require any major remedial work such as rewind or re-insulation, based on the evidence presented. Normal monitoring and maintenance should allow operation out to normal operation of 2023 and in emergency/standby mode to 2027+.

Further, it should be noted that this assessment is valid for normal expected unit service. The consequences of abnormal operation or unpredictable system stress events cannot be predicted.

8.1.1.7 Life Cycle Curve and Remaining Life

The unit is in good condition to achieve a 2023 end of normal generation life. Again, it should be noted that this assessment is valid for normal expected unit service and in emergency/standby mode 2027 with continued PM work and inspections/testing. The consequences of abnormal operation or unpredictable system stress events cannot be predicted.

With the changes to the exciter controls in 2017 and transformer in 2016, this system will also be in good position of meeting a 2023 end of normal operation life date, and in emergency/standby mode 2027 with continued PM work and inspections/testing.

The hydrogen system should be in good position of meeting a 2023 end of normal operation life date and in emergency/standby mode 2027, with continued PM work.

8.1.1.8 Level 2 Inspections – Unit 1 Generator

No Level 2 analyses are specifically required given their current condition and their ability to make a 2023 end of normal life and in emergency/standby mode 2027, provided that the plant maintains their current maintenance and inspection programs, including annual megger tests and hydrogen seals checks.

8.1.1.9 Capital Program Suggestions

No major capital investments are recommended.

8.1.2 Asset 6805 – Unit 1 Generator Lube Oil System

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

8.1.2.1 Description (No major change since 2010/11 Report and 2017)

8.1.2.2 History

Lube oil system failure in 2013 resulted in significant Steam Turbine damage, which was subsequently repaired.

8.1.2.3 Inspection and Repair History

Lube oil system failure in 2013 resulted in significant Steam Turbine damage. The lube oil system, turbine bearing, and journal were repaired. In 2014 both north and south AC Lube oil pump motors were replaced, and DC lube oil pump motor overhauled. The DC lube oil panel was replaced in 2017.

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.

All parts of the generator lube oil system are expected to be able to make their next inspection date in 2018. All are expected to undergo more rigorous evaluation at that time. Aside from any identified maintenance and minor replacement requirements, the system is expected to meet the generation normal operator end date of March 2023 and standby/emergency mode of 2027.

8.1.2.5 Actions

Based on its overall condition assessment, no changes to the 2010/11 and 2017 update Recommended Actions are recommended. Maintaining the ongoing PM program inspections and practices for the lube oil system are most critical.

Assess the requirements for and impacts of quicker start requirements on heater system temperatures in 40-45 ^{o}C range.

8.1.2.6 Risk Assessment

All the risk items of the 2010/11 Condition Assessment and 2017 update report remain as Low Risk, both from a technological perspective and a safety perspective, provided ongoing regular inspections and maintenance PM's are followed. The issue with 2013 Lube Oil system failure on Unit 1 was resolved.

A maintenance strategy will be required for beyond March 2023 regarding turning gear and motor PM maintenance requirements.

8.1.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025+ timeframe range for normal operation.

8.1.2.8 Level 2 Inspections – Unit 1 Generator Lube Oil System

Given the condition historical data reviewed, no Level 2 analysis of the lube oil system is recommended, provided the current inspection and maintenance program for the system is maintained.

8.1.2.9 Capital Projects

No significant capital enhancements for the system are recommended. Maintenance repairs and minor capital replacements found during inspections should suffice to achieve the March 2023 normal operation and 2027+ standby/emergency generation end dates.

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

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 6722 #1 Main Controls 6724 #1 Generator Bus-Duct and Connections 6728 #1 Battery Chargers 7184/7186/7187 MCC's, C2, C3, C4 7193 #1 UPS1 Inverter 270151 #1Turbine Supervisory System 270295 #1Switchgear, 4160V/600V 7182 #1 Power Centre "A" UAB1, (600V) 291668 #1 DCS **COMMON SYSTEMS** 7197. Common, Stage 1, 129VDC Supply System 270297 Control Cables 270298, Power Cables 600V Metric Plugs

8.1.3.1 Description (No major change since 2010/11 Report and 2017 update)

Asset 6722, Unit 1 Main Controls/ Turbine Governor System

- The electronic speed governor, (GE SpeedTronic Mark V), manufactured by General Electric was installed in 1999. The governor is complete with protection and monitors speed, metal temperatures, vibration, and steam valve positions into the turbine. An HMI for operator use is provided in the control room. The end of life of Mark V turbine control system was originally 2013. Its firmware (TSI upgrade in 2015/2016) was upgraded. Additional OEM support and spare cards have been implemented and would be expected to be extended to meet any new end dates.
- U1 DC Panel was upgraded in 2015. Also, some generator protection Schweitzer) and stator ground fault alarms.

Asset 6728, Unit 1 Battery Chargers (Typically 20 Years)

- 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 Primax Technologies Inc. and installed in 2006. Charger 2 is a type P4500F-3-125-60, 575V Input, 129VDC Output, max. Charger output rated 60A.
- 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. Other information: Unit one 250VDC Panel Board was manufactured by Eaton, installed in July 2014 and is a type Pow-R-Line 4.

258VDC Unit 1 and Unit 2 batteries were replaced in 2019. 129 VDC batteries had been replaced previously.

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

8.1.3.2 History (No major change since 2010/11, and 2017 update with exception of an SEL relay).

8.1.3.3 Inspection and Repair History (No major change since 2010/11 and 2017 update)

UPS #1 and #2 life are planned to be extended by re-using parts from UPS #3 and #4 that are planned to be replaced in 2020. Further short-term actions are planned to be considered thereafter.

8.1.3.4 Condition Assessment (No major change since 2010/11 and 2017 update)

The basic DCS, protections, alarms associated with generators and auxiliaries are in fair shape but will need to be re-examined about every five years or so, and if the normal mode of plant operation should be modified to extend beyond March 2023. The 4160v and 600v switchgear equipment appears to be reasonably reliable for the 2023 end of steam life, as long as proper maintenance as scheduled. A short term review should be undertaken of the motor controls, relays/switchgear, and some auxiliary systems such as hydrogen monitoring and generator temperature monitoring regarding replacement or refurbishing, primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment.

If post steam (2021, 2022, or 2023) only one synch condenser operation was needed, then that most stage 1 gear would largely be run on an end of practical life where required basis. Some of the Stage 1 4160 V gear is required for reliability and considering safety. For three running units in stand-by, some more extensive upgrades/refurbishments or replacements will be needed over the next five years.

For stage 1, post steam (2021, 2022, or 2023) the plant have indicated a potential need for the 4160v station board SB12 c/w associated breakers – depending on whether it is needed to keep the station service feed from the terminal station into the plant as well as the black start diesels and overhead line into SB12 (transfer bus through SSB4 to TB12 - SB34; SSB3 kept to feed through AT-C down to C1 and Power Center C; Power Center C in its entirety; both diesel buses). This would apparently require at least 14 electrical distribution breakers to have to remain in service. Given the current state and age of the equipment, some significant capital for refurbishment/replacement is likely (requires cost/benefit analysis).

For post steam standby role, Stage 1 refurbishment/replacement is indicated to include at least twenty-six 4160Vac breakers - 10 for unit motor feeds, 16 for electrical distribution. A more detailed analysis and obsolescence/cost/benefit analysis would be needed.

8.1.3.5 Actions – Unit 1 Electrical and Control Systems

Modest additional actions beyond those in the 2010/11 Condition Assessment and 2017 update report are recommended for the electrical and control systems, provided maintenance and PM work continues and component issues identified are resolved. Some issues that should be examined are:

- Continue PM on battery and chargers. Assess need to undertake battery replacements.
- Maintain OEM support and spare parts, governor, and supervisory systems
- Investigate/re-examine the need for additional actions about every five years or so, and if the normal mode of plant operation should be modified to extend beyond March 2023.
- Review the motor controls, relays/switchgear, and some auxiliary systems regarding replacement or refurbishing, primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment
  - Stage 1 needs for one-unit synchronous condensing role only post steam, including need to keep the station service feed from the terminal station into the plant as well as the black start diesels and overhead line into SB12
  - Stage 1 operating requirements for cold standby/emergency mode post 2023, based on obsolescence and cost/benefit impact on reliability and maintenance costs.

8.1.3.6 Risk Assessment

Overall, the ratings in the 2010/11 Condition Assessment and 2017 update report have not changed, provided PM work continues and issues identified addressed. Most were either low or medium risk, although Stage 1 equipment obsolescence and spare part availability is of concern.

The safety high risk items were the Gen Bus Duct (med/high) and the Blr/Turb MCC C2 C3 (med/high). These likely have not changed, but should be reviewed, as well as critical switchgear,

There is a likelihood that some older items may fail in service, but PM work and redundancy should minimize impacts. A further review of specific Stage 1 critical equipment needs and condition and refurbishment/replacements needs over the next five years is needed for a) the one synchronous condenser unit case; and b) if all three units are to continue in cold standby/emergency operation mode after March 2023.

8.1.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards 2023+ timeframe range for normal operation, although Stage 1 equipment obsolescence and spare part availability is the immediate situation of concern..

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

No Level 2 analyses are currently recommended. Spot checks critical equipment over the next few years, including on:

- Bus Duct – inspection and test (no indication done since 2011; may have been done in 2018)
- Power Centre B, AAB2 – inspection and testing (no indication done since 2011)
- Cables – inspection and testing (no indication done since 2011)

An assessment of Stage 1 switchgear needed for a) the one synchronous condenser unit case, including station service supply; and b) if all three units are to continue in cold standby/emergency operation mode after March 2023.

8.1.3.9 Capital Projects

Given the end of generation life normal mode of March 2023, no further immediate capital enhancements for Unit 1 Electrical & Control Systems Associated with Generators are recommended, unless identified by regular PM inspections or during exercising operations or during the assessment of needs and condition identified previously. Utilization of In-service Failure funding may be warranted where applicable for some short-term issues. Capital for longer term refurbishments/replacements of Stage 1 equipment cannot be committed to until the needs are clear, and a cost/benefit analysis undertaken.

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

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

8.1.4.1 Description (Minimal Change since 2010/11 Report and 2017 update)

8.1.4.2 History (Minimal Change since 2010/11 Report and 2017 update) – CW discharge pipe from condenser replaced in 2017)

8.1.4.3 Inspection and Repair History (Minimal Change since 2010/11 Report and 2017 update)

Hatch along with Stantech carried out an inspection of concrete sumps, and specifically the underside of the Unit 1 East concrete beam. Unit 1 East had a significant longitudinal crack and the underside surface concrete was loose and scaled. Removing the concrete to sound concrete indicated delamination in the cover zone (from beam underside to bottom rebar level) revealed the rebar to be significantly corroded. Concrete coring was undertaken in 2017 indicated that it was in reasonable condition, but structural analysis indicated foot traffic was acceptable but no major equipment or vehicular loading. It was indicated that the condition should be monitored. A Level 2 inspection is planned in 2020 for the Sumps, including as detailed assessment of the Unit 1 East beam.

Further visual inspections of other concrete beams were carried out in 2017 which indicated other concrete beams of Units 1,3,4 was in good condition (minor spalling; rusting evident).

CW Travelling Screens

Travelling screen internals were overhauled in 2017/8. No issues have been experienced with these units. The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short-term performance. Civil floor issues in Pumphouse #1 (see previous item) have been identified and in 2017 a 3rd party review indicated no requirement prior to 2021 and likely could be extended to 2023.

CW Pumps

The west CW pump was overhauled in 2010 and the east CW pump and motor was overhauled in 2014. (Both east and west pump motors were overhauled in 2014). CW pumps are performing well. The units should be able to meet March 2023 normal mode of generation end of life with continued maintenance and an emergency/standby to 2027. Major pump overhauls are scheduled on a twelve-year cycle.

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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. There have been no obvious issues with the systems, but no detailed engineering evaluations and no NDE work has been undertaken – initially there was no indication that PM inspections planned on a three-year cycle in 2014 showed any issues. (Note: None done in 2017). An inspection is planned as part of Level 2 Condition Assessment work in 2020.

8.1.4.4 Condition Assessment

Condition Assessments have not changed substantially since 2010/11 Report. The systems can likely be made to function satisfactorily for March 2023 normal mode of generation end of life. (Concern with the Stage 1 pumphouse civil issues with the floor were examined in 2017 and will be re-examined in 2020/21. No other action required for 2023 end of normal generation life).

8.1.4.5 Actions

The actions identified in the 2010/11 Condition Assessment and in 2017 update (Table 8-23) and in 2017 update largely still apply, and include:

- Continue PM and inspections and carry out CW sump and supply/discharge piping inspection in 2020

8.1.4.6 Risk Assessment

The Risks identified in the 2010/11 Condition Assessment all remain “low”, particularly given the March 2021 to 2023 normal mode of generation end of life.

8.1.4.7 Life Cycle Curve and Remaining Life

The Life Cycle identified in the 2010/11 Condition Assessment and 2017 update) for the various elements of the Unit 1 Cooling Water Systems Associated with Generators has not changed much. Travelling screens and the CW pumps have been inspected and overhauled. The pumps should have a longer life than required for the 2023 normal mode of operation, or the 2027 emergency/standby mode. Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the “Risk Area” will have shifted towards the 2030+ timeframe range for normal operation.

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

Level 2 analyses of the concrete beam in the Unit 1 East sump. Video check as practical of intake and discharge piping are suggested.

8.1.4.9 Capital Projects

No capital enhancements for Unit 1 Cooling Water Systems Associated with Generators are anticipated to be warranted at this time.

8.2 Unit 1 – Lower Priority Systems (2011 Report Identification)

8.2.1 Asset 6699 Unit 1 Boiler System

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 6870 #1 Steam drum, 6871 #1 Downcomers and feeder piping 6871 #1 Lower Waterwall headers 6871 #1 Waterwall tubing 6871 #1 Upper Waterwall headers, and riser piping
	6873/6878 #1 Superheater, headers and tubing
	6878 #1 Reheater, headers and tubing
	6871 #1 Safety Valves
	6700 #1 Furnace structural, hangers and casing

8.2.1.1 Description (Similar to that in 2010/11 Report and 2017 update)

8.2.1.2 History (Change since 2010/11 Report and 2017 update)

NOTE: The boiler system has been a major source of unreliability in 2012 to 2017. Hence in 2017 it was actually considered a key system, if not the key system. It remains a key piece in 2020 to March 2023.

8.2.1.3 Inspection and Repair History

Minor and Major overhauls (last major 2019) usually alternate every year. Major Level 2 inspection and repair projects were implemented on Unit 1 through 3 in 2012 to 2017 as a result of the previous 2010/11 Condition Assessment and significant tube failures and reliability losses in 2015. This has resulted in the sections of the boiler experiencing significant wall thickness loss and/or cracking being replaced in 2016. Results of these are documented in several recent reports.

In 2011 the boiler blowdown tank was replaced.

In Blr Tube Sampling 2012, 2014, 2015 of Unit 1 assessment, tube thicknesses were checked and repaired or replaced as required.

In the Unit #1 & #2 Summary of RH Repairs 2016 Emergency Repairs assessment:

- 7 leaks found in Platens 18,28,29

In the U1 Lower RH Replacement Summary 2016 assessment:

- Many lower RH tubes were found with thickness less than minimum
- Hot ash corrosion (as opposed to Out of Service corrosion) was most prominent
- Tubing previously purchased and additional orders
- Run until failure – major failures in Feb 2016 led to replacement

In 2017 through 2019, significant sections of the economizer and air preheater also underwent deep cleaning to improve air flow and combustion.

In B&W Boiler 2018 Condition Assessment Report, Team Ultrasound Examination reports on Unit 1 are summarized:

- Unit 1 – West BFP discharge elbow and reducer (wall thinning/FAC) – status: been completed
- Unit 1 – Steam drum downcomer penetration (thermal fatigue cracking) – status: been completed
- Unit 1 – Supports (failures/cracking - status: been completed

Unit 1 RH2 Header Repair 2019 in 238-10-6011-164 RH-2 mark up Unit 1 2019 Repair

Economizer

As per part of routine non-destructive evaluation (NDE) inspections, VisTech undertook ultrasonic thickness (UT) measurement readings in 2017 at specified locations on the economizer inlet and outlet headers. In their Unit #1 Economizer Inlet Header Borescope Report of 2017 sep8-10 suggested that things were in good condition and with little change since previous check.

From B&W's HRD 1 and 2 Tube analysis DWD results of 11/05/2017:

- Cold side pitting of tube 117 considerable (6% of wall thickness) – for discussion, not concern; others good
- Residual moisture collects in tubes during longer outages
- Possibly use desiccant or vapour phase corrosion inhibitor and only open steam drums when inspection or maintenance require it

Economizer Tubing

The 2011 Level I assessment estimated the risk level as "Low". Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the inspection, assessment, and management of tubing condition. Boiler tube thinning leading to tube failures has been identified as a reliability risk in an assessment conducted by NLH. Economizer tube wall thickness measurements indicate the end of life estimate is acceptable. No operational issues have been noted since the original assessment; thus, the estimated risk level remains "Low". No specific maintenance actions are required but standard boiler tubing inspections should continue.

Economizer Headers

The 2011 Level I assessment estimated the risk level as "Medium" and "Low" for the inlet and outlet headers, respectively. Borehole cracking has been observed in Units 1 and 2. (Note: Cross-ligament cracking has been observed in Unit 3 and an issue to monitor going forward for all units.) Inlet Tee replacement during period. Recommendations for tighter control of the header temperature have been made to prevent thermal fatigue that can drive the crack growth. FAC has also been observed in the Unit 1 and 2 headers. No operational issues have been noted since the original assessment, but the potential for continued crack growth remains. (The estimated risk level remains "Medium".)

There are no specific expenditures planned for the economizer headers, but Boiler Overhauls are planned for each year. Continued inspections have been part of the regular boiler maintenance under the Level II condition assessment follow-up scope. Instrumentation recommendations have also been made.

Linking Piping

The risk level for the economizer link piping was estimated as "Low". No inspections were conducted, and no operational issues have been noted since the original assessment. (The estimated risk level remains "Low".) There are no specific expenditures planned. No specific maintenance actions are required.

Furnace Water Circuit

The major components of the furnace water circuit consist of the waterwalls, headers, feeder tubes, stream drum, downcomers, and riser tubes. These components had a 2011 risk level of "Medium", with the exception of the upper waterwall headers, which were "Low". Level II inspections since 2011 found inactive pitting in riser tubes, feeder tubes and waterwall headers, and downcomer penetration cracking in steam drum. No operational issues have been noted since the original assessment. The estimated risk levels are unchanged.
There are no specific expenditures planned for the furnace water circuit, but Boiler Overhauls are planned for each year. Continued steam drum downcomer penetration inspections and other occasional inspections are part of the regular boiler maintenance under the Level II condition assessment follow-up scope.

Superheater Headers

The Front Horizontal Space Outlet Header (SH6) and the Superheater Link Piping were assessed in 2011 as "High" risk. The remainder of the superheat headers and attemperator were assessed as Medium or low. Level 2 Inspection efforts in 2017 focused on the SH6 (or Main Steam) headers and outlet nozzles. Inspections found nozzle weld cracks and stub tube cracks in Units 1 and 2. Replication did not found indications of high temperature creep to date. No operational issues have been noted since the original assessment. The estimated risk levels are unchanged.

There are no specific expenditures planned for the superheat headers, but Boiler Overhauls are planned for each year. Continued header inspections at regular intervals are part of the boiler maintenance under the Level II condition assessment follow-up scope.

Superheater Tubing

Superheater tubing was assessed in 2017 as "Low" and "Medium" risk. Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the inspection, assessment, and management of tubing condition.

Boiler tube thinning leading to tube failures had been identified as a reliability risk in an assessment conducted by NLH. Superheat tube wall thinning and inner diameter (ID) oxide scale are contributing to a reduced creep life estimate. (NOTE: i.e.

Reheater Headers

The reheater inlet (cold reheat) and outlet (hot reheat) headers in 2017 were assessed in 2011 as "Medium" and "Low" risk, respectively. Level 2 Inspection were carried out on both headers. No significant findings were noted. Replication did not identify high-temperature creep damage. The estimated risk levels are unchanged.
There are no specific expenditures planned for the reheater headers, but Boiler Overhauls are planned for each year. Continued header inspections at regular intervals are part of the boiler maintenance under the 2017 Level II condition assessment follow-up scope. Info - 238-10-6011-164 RH-2 mark up Unit 1 2019 Repair

Reheater Tubing

Reheater tubing was assessed in 2011 as "Medium" risk. Failures did occur in January 2016 and were repaired/replaced. Risk is now considered "Low". Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the general assessment and management of tubing condition.

Safety Relief Valves

As noted in the 2011 Level I assessment, the HTGS boilers Safety Relief Valves (SRVs) are inspected and maintained as per the SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the desired life.

Furnace Structural Hangers and Casing

The boiler hangers are checked visually annually. No issues have been identified to date. The annual inspections are considered sufficient to maintain the structural hangers to the desired end of life.

The furnace is pressurized, and leaks are repaired promptly to avoid safety concerns in the plant. The casing is generally in good condition. Potential areas of concern that require routine actions are the expansion joints and air-heater seals. Expansion joint repairs are routine maintenance. (NOTE: a recent U2 igniter air duct failure in 2017 where the end of the duct disengaged from the igniter and the backflow of hot combustion gas out of the boiler ignited nearby cables. This incident is not considered to be a result of ageing degradation and thus is not applicable to the Level I assessment for Unit 1).

To identify possible issues with the boiler casing, infrared (IR) cameras could be used. The station should consider the use of IR cameras can identify leaks at an early stage.

Furnace Combustion Systems

The furnace combustion system includes the burners, fans, and air heaters. These components are inspected regularly and maintained by contractors. A recent assessment by Howden Ljungstrom was performed on the air heaters. Air preheater upgrades were completed in 2017. Intensive cleaning undertaken in 2019.

The forced draft fans are subject to routine inspection and repair by an external consultant, Fan Dynamics. Recent reports indicate that the U1 fans are in good condition.

No capital investment is noted, however the routine inspections and repairs recommended by the fan consultant are assumed to address the current and future degradation issues. A Level 2 inspection is planned for 2020.

High Pressure Piping

Main Steam Piping

The main steam piping was assessed in 2011 as "High" risk. The primary concern was for creep and creep fatigue due to the high operating temperature and pressure. Inspections were executed in 2017 as part of the Level II condition assessment. There were no significant findings, but follow-up inspections to monitor for creep damage were recommended. As a result, the risk would now be "Medium" or lower.

There are no specific capital expenditures planned for the main steam piping replacements, but Boiler Overhauls and Level 2 Condition Assessments are planned each year to 2021, and should address the entrance the main steam elbow to control valves/turbine casing – GE considered 2021 OK given operating hours, but should reassess. Focused Level 2 Inspections should continue through 2023 desired end of normal operating life and likely continue every three years during the cold standby/emergency period, with Regulatory required either every year or as may be negotiated with the Regulator.

Cold Reheat Piping

The cold reheat piping was assessed as "Low" risk in 2011. Inspections were executed in 2017 as part of the Level II condition assessment. Minor pitting was noted in Unit 1, but no other findings were noted. There are no specific expenditures planned. No additional follow-up inspections are recommended. CRH drains in good condition. Condensate pots not in service.

Hot Reheat Piping

The hot reheat piping was assessed in 2011 as "Medium" risk. The primary concern was for creep and creep fatigue due to the high operating temperature. Inspections were executed in 2017 as part of the Level II condition assessment. The findings did not indicate degradation of the piping (Note: Some hanger failures were found in 2014 inspections of Units 1 through 3). What was believed to be a weld defect was also identified and repaired in 2016. Follow-up inspections to monitor for creep damage were recommended and continue to be executed.

The hanger failures highlighted the need for regular hanger monitoring. Proper pipe support is critical for high-energy piping as high stress areas can lead to premature failure. Hanger monitoring is now being executed yearly in both the hot and cold condition for all units.

There are no specific capital expenditures planned for the hot reheat piping, but Boiler Overhauls and Level 2 Condition Assessments are planned each year to 2021. Level 2 Inspections should continue through 2023 desired end of normal operating life and likely continue every three years during the cold standby/emergency period, with Regulatory required either every year or as may be negotiated with the Regulator.

High Pressure Feedwater Piping

The high-pressure feedwater piping was assessed in 2017 as “High” risk. The primary concern was for flow accelerated corrosion (FAC) due to the temperature, process chemistry and pipe material. FAC was a known issue for HTGS and additional inspections were executed as part of the Level II condition assessment. Multiple areas of low wall thickness were noted, and the scope was expanded to other at-risk locations in subsequent years. The FAC degradation has led to the pad weld repairs and piping replacements in every unit. The risk is currently assessed to be “Medium Risk” or less, but FAC will continue to be a concern until the end of life.
Boiler Overhauls are planned for each year and Level 2 Condition Assessments to 2019. As the plant ages the scope of repairs and replacements are expected to increase. It is recommended that these Condition Assessments and inspections be continued through to end of life, per the re-inspection times indicated in the previous FAC assessments and likely continue every three years during the cold standby/emergency period, with Regulatory required either every year or as may be negotiated with the Regulator.

No specific capital expenditure is planned. Depending on the results of detailed Condition Assessments, consideration should be given to the procurement of spare piping components so that replacements can be executed in a timely fashion.

Boiler Inspections History and Projections to 2021

Ma Major
Mn Minor

Boiler Overhaul Schedule

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Unit #1	Ma	Mn	Ma	*	Ma	Mn	Mn	Ma	Mn	Ma	Ma	Mn			
Unit #2	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma			
Unit #3	Ma	Ma	Mn	Ma	Mn	Ma	Mn	Mn	Ma	Ma	Mn	Ma			

*No Boiler Overhaul for U1 in 2013

8.2.1.4 Condition Assessment

Boiler and high-pressure piping systems Level 2 inspections, and associated mitigation/repairs (in additional to annual boiler maintenance program) have been ongoing since the 2011 report. Major work has been undertaken in various sections of the boiler such that most of the boiler is currently in reasonably good condition. Nevertheless, one issue that arose in 2017 is the condition of the Boiler Stop Valves (identified in 2011 as having no recent information on condition, and no condition assessment work done to 2016). The unit Boiler Stop Valve was removed in 2017.

Generally, it is considered that the Unit 1 boiler is in reasonably good condition to reach a March 2023 normal operating mode of generation end of life, and with inspections and PM likely to 2027+ in a cold standby/emergency mode. Info - Unit #1 Economizer Inlet Header Borescope Report

8.2.1.5 Actions

Based on the condition assessment and work done on the units since 2011, the following actions are recommended:

- Continue program to end of normal operating mode life of focused detailed Level 2 inspections and tests as per Level 2 Boiler assessments. Including: boiler tube thickness; Superheater Front Horizontal Space Outlet Header; Reheater Outlet Header.
- Continue PM and boiler inspections/repairs per Regulatory requirements to end of normal operating life and discuss changes for period to 2027+ in a cold standby/emergency mode.

8.2.1.6 Risk Assessment

Since the 2011 issue of the Level I report, all of its "High" risk items have been inspected (and repaired as required) per the recommended 2017 Level II scope. Additionally, several "Medium" and "Low" risk areas were also inspected. Within the scope of this report, there have only been two significant failure events causing an extended outage – 2017 U2 igniter air duct failure and Unit 1 Boiler Stop Valve failure. The end of the duct disengaged from the igniter and the backflow of hot combustion gas out of the boiler ignited nearby cables. Although not considered a result of ageing degradation this incident does emphasize that a plant can be vulnerable in many areas, requiring the diligence of personnel to identify issues and prevent larger problems.

Boiler overhauls are planned for each year of normal operation to 2023 and further Condition Assessments to 2019 (focused Level 2 recommended to be continued to end of normal operating life). As in previous years, the expectation is that recommended follow-up inspections from the Level II assessments will be completed. The two major risks are creep in high temperature components and FAC in the feedwater lines. These are both potentially "High" risk areas. Thermal transformation of the high temperature piping and headers has been observed and repairs and replacements have been performed on the feed water piping. Both these areas will continue to require inspection (and repairs as found).

Other degradation mechanisms require monitoring to ensure that they do not continue to progress (e.g. corrosion in the water circuit), or that any progression of damage does not threaten the component integrity (e.g. economizer inlet headers, downcomer penetrations).

The primary High-Risk Level items are:

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Space Outlet Header	Creep and thermal fatigue	3	D	Low to Med
Reheater Outlet Header	Creep and thermal fatigue	3	D	Low to Med

Component	Major Issues	Likelihood	Consequence	Risk Level
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking • Corrosion-Fatigue Cracking • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med

Others are medium or low risk.

Component	Major Issues	Likelihood	Consequence	Risk Level
Economizer Inlet Headers	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	3	B	Med
Economizer Outlet Headers and Link Piping	Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion.	1	B	Low
Upper WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking in flat end welds. Corrosion	2	B	Low
Riser Tubes	Corrosion, Corrosion Fatigue	3	B	Low
Lower WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	3	B	Low
Feeder Tubes	Corrosion, Corrosion Fatigue	3	B	Low
Downcomers	Thermal/Mechanical Fatigue Cracking at the header support locations	3	B	Low
Steam Drum	Thermal fatigue cracking, Corrosion-fatigue cracking	3	C	Low
Superheater Steam Cooled Walls Outlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Inlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Outlet Header	Creep and thermal fatigue	1	C	Low
Superheater Front Support Tube Inlet Header	Creep and thermal fatigue	3	C	Med

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Platen Inlet Header	Creep and thermal fatigue	1	C	Low
Reheater Inlet Header	Thermal fatigue.	1	B	Low
Superheater Link Piping and Attemperator	Thermal/Mechanical Fatigue, Corrosion-Fatigue, Corrosion.	3	C	Med
Economizer Tubes	External corrosion and corrosion-fatigue.	1	B	Low

Piping System	Damaging Mechanism	Likelihood	Consequence	Risk Level
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med
Hot Reheat	• Thermal/Mechanical Fatigue; Corrosion; Creep, Creep-Rupture, Cracking • Thermal/Mechanical Fatigue; Corrosion-Fatigue; Cracking, Corrosion	3	C	Med

8.2.1.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report and the major Level 2 Inspections and mitigations that have been completed in 2012 to 2019, the primary change to the Life Cycle Curve would be that the yellowed “Risk Area” will all have shifted to area between 2025 and 2030+ timeframe range for normal operation.

It is likely legacy impacts will have greater effects on component replacements and refurbishments going forward to 2023. With ongoing inspections and refurbishments, normal generation life of 2023 and end of emergency/standby generation life in March 2027+ is achievable with good reliability.

8.2.1.8 Level 2 Inspections – Unit 1 Boiler System

The risk ratings are lower than in the original Level I assessment. While advanced age of the station is an issue, continued inspection and maintenance and replacements/repairs have mitigated the highest of these concerns

Regular maintenance and follow-up on high risk items remain important for safe and reliable plant operation. Station programs credited here, and other regular inspections must be continued and the findings addressed. Changes to the programs or regular inspections can impact the likelihood of a failure event, if not properly mitigated.

Given the condition historical data reviewed, the required Level 2 analyses, assuming that the current plant inspection and maintenance program is maintained or improved, as per current Level 2 program results. In particular Level 2 work should continue on those elements identified in the risk analysis as "high" (and repeated below).

Component	**Major Issues**	**Likelihood**	**Consequence**	**Risk Level**
Superheater Front Horizontal Space Outlet Header	Creep and thermal fatigue	3	D	Low to Med
Reheater Outlet Header	Creep and thermal fatigue	3	D	Low to Med
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med

From the B&W Boiler 2018 Condition Assessment Report, the following comments were noted from the previous 2017 AMEC report:

Table 4-1 Amec Inspection Recommendations for NLH HTGS Unit 1

Component/Location	Inspection Date	Inspect for	Methodology
Economizer Inlet Header	2020	Borehole ligament cracks	Visual and PAUT
RH Inlet Header	None before 2022		
RH Outlet Header	None before 2022		
SSH Inlet Header	None before 2022		
SSH Outlet Header	2019	Creep	Visual and Replica
WW Lower Header	None before 2022		
WW Upper Header	None before 2022		
High Pressure Feedwater Header	----		
PSH Outlet Header	----		
Economizer Inlet Header Piping	None before 2022		
Feedwater Piping	None before 2022		
Link Piping to Attemperator	None before 2022		
Boiler Feed Pump Piping	2018	Wall thinning / FAC ***West BFP discharge elbow and reducer***	UT grid
Cold Reheat Steam Piping	----		
Hot Reheat Steam Piping	----		
Main Steam Piping	----		
RH Attemperator Refill Piping	----		
SSH Attemperator Piping	----		
Steam Drum	2018	Thermal fatigue cracking ***Steam drum downcomer penetration***	MT
Supports	2018 & 2020	Failures / cracking	Visual / MT
Economizer Tubes	None before 2022		
Lower Vestibule Feeder Tubes	None before 2022		
Lower WW Header Feeder Tubes	None before 2022		
WW Tubes	None before 2022		
PSH Tubes	None before 2022		
SSH Tubes	None before 2022		
RH Tubes	None before 2022		
Riser Tubes	----		

From 2019 B&W Condition Assessment Report.

Table 4-1 Inspections on HTGS Unit 1

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
1	Header	SH-6 Header Outlet Nozzle Welds	Creep Crack (2015)	2019	No active cracking	2025	PAUT, MT, Replica
1	Header	SSH Inlet (SH5) Tube-to-Header Welds	Cracks (2018)	2018	Cracks, excavated, and weld repaired	2020	MT, UT
1	Header	SSH Outlet (SH6) Tube-to-Header Welds	Cracks (2018)	2018	Cracks, excavated, and weld repaired	2020	MT, UT
1	Header	RH Outlet (RH2) Tube-to Header Welds	Cracks (2018)	2018	Cracks, excavated, and weld repaired	2020	MT, UT
1	Header	RH Inlet (RH1) Tube-to Header Welds		2018	No indicators observed	2021	MT, UT
1	Header	Economizer Inlet Header	Cracking	2017	Borehole cracking unchanged. Reinspect in 3 years	2020	Internal visual
1	Pipe	East Hot Reheat Combined Stop Valve Weld		2019	No degradation at welds	West, Reheat CSV Weld 2022	PAUT, MT, Replica
1	Pipe	Main Steam Turbine Stop Valve Weld		2019	No degradation at welds	West Main Stop Valve Weld 2022	PAUL, MT, Replica
1	Pipe	FAC Site 1-1	FAC (2012)	2016	Reinspect in 4.3 years	2020	UT grid
1	Pipe	FAC Site 1-2	FAC (2012)	2016	Reinspect in 6.6 years	2022	UT grid
1	Pipe	FAC Site 1-3	FAC (2012)	2018	Pad weld in 2015; ASME min in 6 years	2021	UT grid
1	Pipe	FAC Site 1-4	FAC (2012)	2015	Reinspect in 7.9 years	2023	UT grid
1	Pipe	FAC Site 1-5	FAC (2012)	2016	Reinspect in 7.0 years	2023	UT grid
1	Pipe	FAC Site 1-6	FAC (2012)	2015	Reinspect in 21.2 years	2025	UT grid

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
1	Pipe	Steam Drum Downcorner nozzle	Thermal fatigue cracking	2018	No indications observed	2023	MT
1	Tubes	Boiler Floor Tubes	Wall Thinning	2019	One location on Hot Side below recommended repair/replace thickness, others approaching this value	2020 (Hot Side) 2025 (Cold Side)	UT
1	Tubes	Waterwall Tubes	Wall thinning/pitting	2019	Some pitting and ID scale destabilization due to upset chemistry event	2025	Metallurgical Assessment
1	Tubes	Lower Vestibule Feeder Tubes	Pitting	2017	No cracking, minor pitting	2025	PAUT
1	Tubes	Economizer Tubing	Wall Thinning, Creep	2016	Wall thickness above repair/replace criteria	2025	UT
1	Tubes	Primary Superheater Tubing	Wall Thinning, Creep	2016	Wall thickness, above repair/replace criteria	2025	UT (NOTIS RLA)
1	Tubes	Secondary Superheater Tubing	Wall Thinning, Creep	2016	Wall thickness at some locations fell below repair/replace criteria	2021	UT
1	Tubes	Reheater Tubing	Wall Thinning, Creep	2016	Wall thickness at some locations fell below repair/replace criteria	2021	(NOTIS RLA)

8.2.1.9 Capital Projects

Significant improvements have been made in the Boiler Systems in 2011-2019. No specific additional capital enhancements for Unit 1 Boiler System are warranted at this time, other than continued focused Level 2 inspections and associated mitigation measures to end of normal generation mode life.

8.2.2 Asset 6708 – Unit 1 Feed Water System HP Heat Exchangers (Chapter 8.2.2 in 2011 Report)

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

8.2.2.1 Description (No major change since 2010/11 and 2017 update)

8.2.2.2 History (No major change since 2010/11 and 2017 update)

8.2.2.3 Inspection and Repair History (No major change since 2010/11 and 2017 update)

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. High pressure feedwater discharge piping had Level 2 done and mitigated. No other Level 2 inspections done, but not high priority

8.2.2.4 Condition Assessment

The high-pressure feedwater heaters were assessed in 2011 as "Medium" and "Low" risk. No inspections were planned or executed but the condition is assessed through water level monitoring. In the last 10 years only one tube failure has been recorded and no other operational issues have been noted since the original assessment. Thus, the condition and associated estimated risk level remains unchanged.

In the BF Pump DCI Report 2018, one boiler feed pump was noted as being refurbished in 2018. It was also noted that U1 East BF was swapped out in Sep 2015 swap (last swap was in 2009).

No issues identified. The HP heaters and boiler feed pumps and motors are expected to meet the March 2023 normal mode generation end of life and 2027 emergency/standby life. The BFP and motors are tested and inspected regularly. There is a spare pump stage available and a spare BFP motor. The HP Htrs have given no indication of issues and the plant should be able to address single failure issue in short term. The High-Pressure feedwater discharge piping had Level 2 done and mitigated in 2017.

8.2.2.5 Actions

Based on the Condition Assessment, no Actions beyond ongoing inspections and PM are recommended.

8.2.2.6 Risk Assessment

Both from a technological perspective and a safety perspective, the Risk Assessment associated with the HP Heaters and Boiler Feed Pump/Motors is low. The BFP and motors have been tested and inspected regularly and there is a spare pump stage and spare motor available. The HP Htrs have given no indication of issues and the plant should be able to address single failure issue in short term.

Component	Tag Name	Major Issues	Likelihood	Consequence	Risk Level
Unit #1 HP Feedwater Heater #4	HP-4	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	3	B	Medium
Unit #1 HP Feedwater Heater #5	HP-5	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	3	B	Medium
Unit #1 HP Feedwater Heater #6	HP-6	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	3	B	Medium
All HP Feedwater Heaters		SCC, Thermal/ Mechanical Fatigue	1	C	Low

8.2.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" will all have shifted towards the 2025 to 2030 timeframe range for normal operation.

The curves indicate that the remaining life (RL) of the Unit 1 HP Heat Exchangers (and the associated feedwater systems) are very likely able to reach the desired life (DL) March 2023 end date for normal mode of generation

For the Unit 1 Boiler Feed Pumps. The pumps have been and continue to be refurbished on a six year cycle using a spare pump section. They are very likely able to reach desired normal generate mode end date of March 2023 for generation and 2027 emergency/standby mode.

8.2.2.8 Level 2 Inspections – Unit 1 Feed Water System HP Heat Exchangers

Given the condition historical data reviewed, Level 2 monitor testing of HP feedwater discharge is likely warranted. No other Level 2 warranted, if maintenance and PM's continue.

8.2.2.9 Capital Projects

No additional suggested capital enhancements for the system are recommended. Variable speed drives and HP #5 heater replacement are not warranted.

8.2.3 Asset 7053 – Unit 1 Feedwater System – Deaerator (Chapter 8.2.3 in 2011 Report)

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 (No major change since 2010/11 and 2017 update)

8.2.3.2 History (No major change since 2010/11 and 2017 update)

8.2.3.3 Inspection and Repair History (No major change since 2010/11 and 2017 update)

A Level 2 inspection was performed in 2017 on deaerator storage with no major findings/actions.

8.2.3.4 Condition Assessment

The deaerator and deaerator storage tank were assessed in 2011 as "Medium" and "Low" risk in the Level I report. The storage tank is inspected every year as part of regular maintenance. Local repairs are regularly performed but there have been no significant issues noted. The unit 2 deaerator had a Level 2 inspection in 2017 was performed on deaerator with no major findings/actions. The status of unit 1 is assigned similar.

No issues/changes in the 2011 Report on the condition assessment of the Unit 1 feedwater system - deaerator was identified. The Unit 1 deaerator and storage tank are considered in good condition and able to achieve generation end of life in March 2023 and the 2027 emergency/standby mode.

8.2.3.5 Actions

No new high priority actions were identified. Maintain regular PM's/inspections.

8.2.3.6 Risk Assessment

The risk assessment associated with the Unit 1 feedwater system - deaerator, from a technological perspective and a safety perspective, is illustrated below. None are a high level or life limiting risk.

Component	Major Issues	Likelihood	Consequence	Risk Level
Deaerators	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	3	B	Medium
Deaerator Storage Tanks	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	2	B	Low
Deaerators/ Storage Tanks	Corrosion-Fatigue and Thermal Fatigue,	1	D	Medium

8.2.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve t is that the yellowed “Risk Area” will have shifted towards the 2025+ timeframe range.

The curve would indicate that the remaining life (RL) of the Unit 1 Feedwater System - Deaerator exceeds the desired life (DL) normal mode end date for generation of March 2023, and 2027 emergency/standby mode.

8.2.3.8 Level 2 Inspections – Unit 1 Feedwater System - Deaerator

Given the condition historical data reviewed, no additional Level 2 analyses are required. A Level 2 inspection of the deaerator with internals removed that was originally planned for 2020 to check for flow accelerated corrosion should be assessed.

8.2.3.9 Capital Projects

No additional capital enhancements for the Unit 1 feedwater system – deaerator are suggested.

8.2.4 Asset 6711 – Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers

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

8.2.4.1 Description (No major change since 2010/11 and 2017 update)

8.2.4.2 History (No major change since 2010/11 and 2017 update)

No plugs required in 2017.

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 discussions with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 1.

8.2.4.4 Condition Assessment (No major change since 2010/11 and 2017 update)

The Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered in good condition and able to achieve generation end of life in March 2023, or 2027 emergency/standby mode. A spare condensate extraction motor procured and available for use in normal mode of Unit 1 or 2.

8.2.4.5 Actions

Based on the Condition Assessment, no Actions are recommended for the Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers. Maintain regular PM's/inspections.

8.2.4.6 Risk Assessment

There has been no significant change in the Risk Assessment associated with the system from 2010/2011 C.A or 2017 update reports, both from a technological perspective and a safety perspective. There are no high priority issues. The Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered low risk, able to achieve end of normal mode of generation life and able to meet end of generation life in March 2023 and 2027 emergency/standby mode.

8.2.4.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will likely have shifted towards the 2025 to 2030 timeframe range.

The Feed Water System LP Heat Exchangers will likely be able to reach the March 2023 normal mode end date for generation. And the 2027 emergency/standby mode. Although no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is likely not warranted at this time given the March 2021 end date.

8.2.4.8 Level 2 Inspections – Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers

Given the condition historical data reviewed, No Level 2's inspections are required, provided ongoing inspection and maintenance program and PM's continue.

8.2.4.9 Capital Projects

No additional capital enhancements for the system are suggested.

8.2.5 Asset 271316 – Unit 1 Condenser

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

8.2.5.1 Description (No major change since 2010/11 and 2017 update reports)

8.2.5.2 History (No major change since 2010/11 and 2017 update reports)

8.2.5.3 Inspection and Repair History

Unit 1 condenser is in reasonable shape for its age.

The number of plugged tubes and the rate of increase in plugging has historically been quite low. The condition is monitored, but no aggressive inspection program is either in place or seems to be required.

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 have historically been identified as being in good condition.

The condenser steel piping at inlet and outlet between the condensers and the underground concrete pipes, according to station staff, have been replaced once and the steel piping appears to have been replaced/refurbished. The discharge piping from the condenser was replaced in 2017.

No additional information on Shell, Hotwell or Waterboxes were identified after the 2008 inspection reports that confirmed that all were in good condition. There appears to be some concern on the thickness/corrosion of the steel waterbox shell. No additional information was identified. A Level 2 inspection of the condenser waterboxes is planned for 2020.

In the Vacuum Pump DCI Report 2018, it was noted that one was refurbished in 2018.

8.2.5.4 Condition Assessment

Generally, the condition assessment of the Unit 1 condenser has no major immediate issues. A Level 2 inspection of the condenser waterboxes is planned for 2020 (2018 was not implemented). The 2010/11 C.A and 2017 update study indicated refurb/replacement of vacuum pumps and motors was warranted, but not a high priority, assuming monitoring and maintenance was kept up.

8.2.5.5 Actions

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

- Continue PM's, including vacuum pump and motor checks.
- Undertake a condenser waterbox material thicknesses check (repair if/as required).
- Overhaul vacuum pumps and motors, as PM's warrant

8.2.5.6 Risk Assessment

The risk assessment associated with the Unit 1 condenser and auxiliaries in 2011 and 2017 had no high risks. Little has changed and no new high risks were identified, although testing/inspection of wall thicknesses of elements of the water boxes is considered warranted, but not critical.

8.2.5.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" for the Vacuum Pump would have shifted to 2017-2022.

The curves indicate that the remaining life (RL) of the Unit 1 Condenser can reach the desired life (end date for normal mode generation and 2017 emergency/standby mode 2023. The exception to this, might be the condenser waterboxes and the vacuum pumps/motors (relatively minor issue that can be readily addressed if/as it occurs).

8.2.5.8 Level 2 Inspections – Unit 1 Condenser

Given the condition historical data reviewed, a Level 2 analyses of the condenser waterbox/tubesheet is considered warranted.

8.2.5.9 Capital Projects

The suggested typical capital enhancements for the Unit 1 condenser are:

- No new capital, subject to waterbox thickness checks (if required likely $750k$ all units).
- Vacuum pump/motor replacements as PM's warrant.

8.2.6 Asset 8777 – Unit 1 FD Fans and System (Chapter 8.2.6 in 2011 Report)

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 Blr Heavy Oil System
	6990 #1 Boiler Light Oil
Components:	8777 #1 Boiler FD Fan System 6943 #1 Boiler FD Fan East 6944 #1 Boiler FD Fan West 6954 #1 Boiler Steam Air Heater East 6955 #1 Boiler Steam Air Heater West 6914 #1 Boiler Main Air Heater East 6915 #1 Boiler Main Air Heater West
	6917 #1 Boiler Gas Passes 6920 #1 Boiler Sootblowing System 6933 #1 Retractable Sootblowers 6934 #1 Rotary Sootblowers 8789 #1 Air Heater Sootblowers
	6988 #1 Boiler Heavy Oil Pump East 6994 #1 Boiler Heavy Oil Pump West 6995 #1 Boiler Heavy Oil Pump steam, valves and pipe 6998 #1 Boiler Heavy Oil Firing 6999 #1 Boiler Light Oil Pump West 8976 #1 Boiler Light Oil Pump East 8977 #1 Boiler Light Oil Pump West
	6979 #1 Boiler Air Supply Seal Air 6982 #1 Boiler Scanner Air System

8.2.6.1 Description (No major change since 2010/11 Report and 2017 update reports)

Unit 1 has two 50% duty 4KV AC 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 speed drives installed in 2015, along with the original variable inlet vanes. These allow the required amount of air into the boiler furnace to ensure that the fuel oil is completely burned.

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

Variable Speed/Frequency Drives were added to the FD fan motors in 2015 and a spare FD fan motor purchased (common to Units 1 and 2). Major in-depth air preheater and economizer cleaning were undertaken in 2017 to reduce generation derating due to air system issues. Poor quality oil (high silica, alumina, susceptible to separation) was utilized in 2015. It caused significant damage to fuel handling systems (heaters, filters, burner tips, pumps) as well as tank deposition requiring cleaning. The fuel specification was subsequently modified, and the fuel improved. It resulted in a major expenditure in 2016 on fuel storage and handling system as a result of damages incurred using poor quality fuel under a new fuel supply contract.

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.

The VFD’s are used with the vanes open. VFD’s have experienced some cell failures when started up after outages. The power cells overload at 85%. Several of sensors/relays high temp causes trips and alarms due to blocked filter (every 1-2 weeks) in VFD cells.

The Ljungstrum air preheater were refurbished in 2017, and deep cleaned (high pressure wash of HE baskets – while removing a substantial amount of accumulated ash; still considered to overall have had minimal success). Further cleaning and some equipment replacement in 2019 have enhanced performance.

From HTGS 2017 Unit # 1 FD Fan NDE Reports Aug 24, 2017 (East Fan), yearly magnetic particle examination revealed some issues that were repaired. Fan internal inspection was being considered for 2020 as part of larger Level 2 Condition Assessment project, subsequently cancelled.

Holyrood Station HOW 0828 (6-28-14) June 28, 2014 Unit 1 identified work done during an emergency service on the East airpreheater needed to address the condition of the guide bearing after all the trunnion bolts had sheared off. The hot end circumferential seals were damaged and removed but replacements left for subsequent scheduled outage. The hot end post seal was replaced, and the cold side was found serviceable.

It was recommended that at next outage:

- Complete and detailed inspection of both APH’s
- Replace hot end circumferential seals on East APH (not installed during emergency outage)
- Check East levelness
- Perform regular oil sampling/analysis on rotor guide bearing, support bearing, and gearbox on both APH’s
- Continue APH maintenance per manual

From A028042-01 - Field Service REPORT - Babcock Wilcox JL Hydro Holyrood Station – ACROSS Unit 1 Sep 2016, it identifies:

- Unit 1 rotors are in good condition for age – repair with normal mtce to spec
- No major issues preventing APH operation after repairs
- All rotating air seals need replacement and support angles for circumferential seals
- Cold end elements thinned and fracturing from corrosion and cleaning – replace cold element

From A031090-01-FIELD SERVICE REPORT - Babcock Wilcox- Hydro Holyrood - 8-17-17 Unit 1

The inspection and repair work indicated that both APH's were in good condition except for cold side sealing surfaces separating air and gas sides showing normal wear and material loss from erosion. New sealing surfaces were applied to east side. The west side would be monitored by the station. The east rotor was water washed.

From B&W report A031090-03 - Field Service advisory - BW - NL Hydro Holyrood Station - Goetschius - 12-2-17 Unit 1 High Press Drop, Howden consulted on issues with high gas and air side airpreheater pressure drop on Units 1 and 2:

- Design gas side pressure drop – 5.1" H2O; current 8.4' H2O
- Design air side pressure drop – 3.4" H2O; current 6.43" H2O
- Steam sootblowers – design 145 psig 200oF superheat; actual: 160 psig, 70oF superheat
- MgO additive discontinued in 2014
- Initial hot water wash water cleaning had minimal effect; high pressure 2500 psig worked for 90% of tubes
- Low S and a low viscosity, indicate a less typical #6 oil – should result in less acid condensed enhanced fouling or poor atomization fouling blockage
- Vanadium of 200 ppm appears significant and may warrant MgO additive – produces molten salt (Van/Sodium) corrosion of metallic type in upper furnace that finds its way into airpreheater over the long term (hence deposits are somewhat magnetic in nature)

B&W did not recommend increasing the low superheat temp of the sootblowing steam, while acknowledging that it would be a factor in the buildup of deposits - largely because the lower level seemed to work for years. B&W quoted for replacing hot end baskets.

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 boiler contractor. 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 that 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 loading impacts has been significantly reduced.

Asset 6705 Fuel Oil Firing (Valve Trim – Atlantic Controls)

Major parts of the fuel oil filters and heaters were replaced/refurbished in 2015 as a result of the purchase and use of a higher silica/alumina/vanadium oil that year. Fuel changes and the new equipment have improved the situation. Recent reports regarding the condition of the light and heavy oil systems were not available or reviewed. However, the systems had visually appeared to be in reasonable condition. 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. For faster starts, a suggestion that temperature in standby maintain 50 °C versus current temperature switch at 85-90 °C (more consistent with 0.7% sulphur oil vs 2.5% sulphur oil historical basis). For low flow, the main fuel oil control valve is oversize and could use a low flow control valve circuit.

In 2019 significant deposition was noted in unit fuel filters and heaters. The material was very difficult to clean and a Quebec company's proprietary process was applied to clean out heater tubes. It appears that fuel oil separation and deposition has occurred resulting in a gooey solid coming from both the main and day tanks. (Note that the main tank suction heaters have been covered especially top surfaces with a very hard coating that is no doubt reducing their thermal effectiveness.

8.2.6.4 Condition Assessment

Given the history and operating pattern. The condition assessment of the Unit 1 FD fans and system would suggest:

- Involvement of these systems in the annual boiler inspection is critical
- The FD Fan is in reasonable shape
- The FD fan motors are at risk given their age and the impact of VFD operation
- A spare motor has been and will likely continue to be a critical spare asset

Some of the work in the 2011 to 2019 period which helped with Condition Assessment were:

- Air preheater and economizer deep cleaning to address air system output derate
- Boiler hangers were reset to address load issues.
- The oil system which had issues in 2015 requiring major refurbishment have been resolved through an improved oil specification/procurement and system refurbishments/replacements. Although another but different problem appears to have arisen in 2019.

The sootblowing system is somewhat limited and it could be improved in terms of coverage and efficiency. More frequent use of APH sootblowing also appears warranted (continuous versus once per day or per shift). No significant capital investment is foreseen.

The Unit 1 FD Fans (& System) are considered in good condition to meet March 2023 generation end of life, provided combustion air issues remain resolved. That could change if unusual operating requirements should result in performance deterioration (cycling, two-shifting, excessive low or high load operation, fuel system clogging).

8.2.6.5 Actions

The primary high priority actions recommended for the Unit 1 FD Fans (and System) is to:

- Further assess the VFD operation/optimize air system to maintain unit capacity
- Continue monitoring delta air press to time additional APH/Econ cleaning
- More use of APH sootblowing
- Inspection of FD fans and APH's internally in 2020
- Assess fuel plugging issues for solution for near and longer term
- For faster starts, assess temperature in standby maintain 50 °C versus current temperature switch at 85-90 °C (more consistent with 0.7% sulphur oil vs 2.5% sulphur oil historical basis).
- For low flow, assess use of a low flow control valve circuit.

No other high priority items remain from 2011 or since that time, provided annual boiler work and PM's are continued.

8.2.6.6 Risk Assessment

No high-risk issues from the 2011 report associated with the Unit 1 FD Fans (and System), both from a technological perspective and a safety perspective, remain.

Further maintenance and investigation associated with the air system is considered appropriate for:

- APH and economizer pluggage
- VFD operation optimization
- FD fan motor age (currently managed through spare motor availability)
- Fuel filter and heater pluggage

8.2.6.7 Life Cycle Curve and Remaining Life

An updated/revised Life Cycle Curve (Figure 8-19 in the 2011 report) is not within the scope of the study.

Given the experience since the 2010/11 Condition Assessment report, the primary changes to the Life Cycle Curve are:

- The plant has procured spare FD motor
- An additional yellowed "Risk Box" for the combustion system and VFD in current timeframe addressing the Unit issues with air system optimization and pluggages (APH, economizer, fuel system)

Given the availability of the spare FD motor, the Unit 1 FD Fans (& System) is expected to meet or exceed the desired life (DL) March 2023 end date for generation. The age of the large 4 kV motors makes continued maintenance program testing/monitoring programs desirable to effectively monitoring their status.

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

Given the condition historical data reviewed, no Level 2 analyses are considered required. Level 2 inspections of the FD fans and airpreheaters were planned for 2020 as part of larger Level 2 project. Continued inspections associated are considered warranted (fuel system plugging; APH and FD fan inspections; APH cleaning).

8.2.6.9 Capital Projects

Given previous air duct refurbs, spare FD fan motor procurements and VFD's, no additional capital projects are recommended beyond current plans.

8.2.7 Asset 6919 – Unit 1 Stack and Breaching (Chapter 8.2.7 in 2011 Report)

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 270294 #1 Stack Breeching

8.2.7.1 Description (No major change since 2010/11 and 2017 update reports)

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.

8.2.7.2 History – No Major Change Since 2017 Updated Report

Stack repairs (liners, breeching) were completed in 2012

8.2.7.3 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 in 2014 indicated 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.

Stack repairs to the liners and breeching were completed after 2011. Inspections are typically undertaken every three years.

In 2014 an internal and external Remote Access Technology (Aug 2014 RAT Inspection Assessment) was carried out on Stack #2. The 1/4/2016 B&W/ICM Assessment of 2014 report indicated:

Observations

During ICM's review of the inspection report provided to us, the following issues were observed with the chimney:

- Approximately 12 cracks (vertical and horizontal) and 7 small spalls were visible on the concrete column exterior.
- The external paint is in poor condition for the full height of the chimney.
- There are three bent rungs, one loose rung, one missing stand-off and a warped section on the access ladder.
- The ladder has two different safety rail types in the top and bottom halves.
- The north down lead cable is broken at the base of the chimney.
- There is surface corrosion on some of the rigid conduit. Also, some of the junction boxes are damaged. Finally, the sheath on the flexible conduit is damaged in areas, and incorrect fasteners are used.
- The handrails on the southwest and east sides of the lower platform are loose. Also, there is a broken guardrail on the north side of the top platform.
- The 160' platform level davit arm and winch system have surface corrosion on their components.
- The aviation light fixtures on the east and west sides of the lower platform are missing some of their fastening hardware.
- Areas of minor cracks, small spalls, open construction joints and moisture seepage were observed throughout the entire visible column interior.
- The carbon steel liner immediately below the stainless-steel transition was found to be corroded.
- Missing and defective refractory bricks were observed in the breaching interior at the chimney entry.

Recommendations

After a review and study of the information obtained during the inspection, we recommend that the following repairs be carried out on the chimney at the earliest possible convenience:

- Grind out and fully expose all cracks, spalls and failed repairs throughout the exterior concrete sheel and seal/repair.
- Thoroughly wash down and prepare the entire surface of the chimney exterior and apply two coats of quality protective paint.
- Repair broken down lead on north side of chimney base.
- Secure loose handrail section on both platforms

Assessment Report 2014

- Install a stand-off on the access ladder 314' above the ground.
- Replace safety rail above lower platform to match the safety rail system used in the bottom half.
- Replace missing refractory bricks in the breaching inlets.

The last inspections were in 2017 and 2018. Stack inspections in 2017 and 2018 indicated that some recoating might be warranted, but generally that the concrete stacks are in reasonably good condition and are expected to be able to make the then March 2021 generation end date.

In B&W/ICM Report – April 2018, repair scopes of work for a quote for the #1 and #2 stacks were based on the review of the inspection reports that were provided. The repair scope of work for the #3 stack is based on the stack inspection completed by ICM in 2015.

Subsequent to completing the review of the inspection reportsit5 was advised that the stacks would only remain in operation for another five years at most. Based on this information, the repair scope of work originally quoted for the #1 and #2 stacks was reduced to immediately necessary repairs to the concrete column and stack accessories. The painting the stacks or altering the ladder safety rail, nor the work on the breaching brick were included.

When then advised that the stacks could possibly continue in operation to as late as 2023 and would likely be left standing for many years beyond that date, revised quotes that included applying a new coating to the exterior of each of the stacks to help protect the concrete from moisture penetration were added. The scope of work for each of the stacks quoted below includes these revisions.

#1 Stack Repair - Scope of Work

- Grind out and fully expose all cracks, spalls and failed repairs throughout the exterior concrete shell and seal / repair.
- Thoroughly high pressure (min 7000 psi) wash down and prepare the entire surface of the of the chimney exterior and apply a sealer coat to all exposed concrete and apply two coats of quality protective paint specifically designed for coastal environments.
- Repair broken down lead on north side of chimney base.
- Secure loose handrail sections on both platforms.
- Install a stand-off on the access ladder 314’ above the ground.

Price

Our total lump sum price to carry out all of the repair work on both the #1 and #2 stacks as described above is Four Hundred and Eighty-Five Thousand Four Hundred Dollars ($485,400.00) GST / HST extra.

Notes

- This price assumes that work on all 3 stacks can be done consecutively so only need to mobilize and demobilize once.

Price Breakdown: The price quoted above breaks down as follows:

Mobilization / Demobilization = $22,400
Chimney #1 Repairs = $148,200
Chimney #2 Repairs = $144,200
Chimney #3 Repairs = $170,600
Total = $485,400

From 2415-18 Report Stack #1 (Low Res) Dec 19, 2018, the following:

Repairs

After the inspection was completed, the following repairs were done:

- Four open construction joints were repaired.
  - A construction joint 127' above the ground on the north side.
  - A construction joint 187' above the ground on the north side.
  - A construction joint 165' above the ground on the south side.
  - A construction joint 187' above the ground on the east side.
- Four concrete spalls in the interior concrete were repaired
  - A spall 187' above the ground on the north side.
  - A second spall 187' above the ground on the north side.
  - A spall 165' above the ground on the southwest side.
  - A spall 187' above the ground on the south side.
  - A spall 180' above the ground on the east side.
  - A spall 203' above the ground on the east side.
  - A second spall 203' above the ground on the east side.
- A 3' missing section of the lightning protection system ground connection between the cap and the top circuit cable was replaced.
- The loose platform handrails were repaired and a broken mid-rail on the top platform was also repaired.
- The aircraft warning lights were repaired

Observations

During the review of the inspection noted and photographs, the following issues were observed with the chimney:

- The external paint is in poor condition for the full height of the chimney
- The ladder has two different safety rail types in the top and bottom halves.

Recommendations

After a review and study of the information obtained during the inspection, we recommend that the following repairs be carried out on the chimney at the earliest possible convenience:

- Thoroughly wash down and prepare the entire surface of the chimney exterior and apply two coats of quality protective paint.
- Replace safety rail above lower platform to match the safety rail system used in the bottom half.
- Continue to inspect the stack at regular intervals

8.2.7.4 Condition Assessment

The stack is inspected every three years. Stack repairs to the liners and breeching were completed after 2011 and considered in reasonably good condition. The 2017 and 2018 inspection and repair work indicated that most repairs had been completed, but recommended that the stack be coated, but this has been deferred. The stack and system are expected to be able to make the March 2023 normal mode generation end date and the cold standby/emergency generation mode in 2027+, but the stack should be re-coated.

8.2.7.5 Actions

Based on the condition assessment, the actions recommended are:

- Continue stack regulatory inspections in 2020 and beyond
- Consider re-coating in 2021-2023 period, especially if future stack inspections verify requirement or if generation extension possible

8.2.7.6 Risk Assessment

The high risk associated with breeching in the 2011 report was addressed. Subsequent inspections and repairs have been completed such that no other high risks were identified as current, except re-coating. Consideration of the stack re-coating recommended in the 2017 and 2018 inspections if verified in a future inspection should be completed, likely in 2021 to 2023 period.

8.2.7.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change is that the Existing Breech risk area would disappear, and the others would not likely change. Stack re-coating might be added for 2021 to 2023 period.

The Unit 1 Stack is considered able to reach the desired life (DL) of manual generation mode of 2023 and likely well beyond to 2027 emergency/standby end date provided current inspections and maintenance are maintained, particularly stack re-coating.

8.2.7.8 Level 2 Inspections – Unit 1 Stack and Breaching

No additional Level 2 analyses are considered to be required, provided the current plant regulatory inspection and maintenance programs are maintained or improved. Continue stack inspections and monitor degradation of stacks and liners. Undertake stack re-coating if/when justified in future inspection reports, likely in 2021 to 2023.

8.2.7.9 Capital Projects

No additional capital work is recommended, except stack re-coating is recommended in 2021-2023 period.

8.2.8 Asset 6723 - Unit 1 Electrical and Control Systems (including DCS) Associated with Steam Systems (Chapter 8.2.8 in 2011 Report)

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 270151 #1 Turbine Supervisory System 7173 #1 Burner Management 309897 #1 Boiler Protection & Control

8.2.8.1 Description (No major change since 2010/11)

8.2.8.2 History (No major change since 2010/11)

8.2.8.3 Inspection and Repair History (No major change since 2010/11)

8.2.8.4 Condition Assessment

The condition assessment of the systems is as follows:

- Foxboro would normally be considered to approach obsolescence in 2021
- Switchgear and Turbovisory remain key issues. Additional spares have been procured.
- Addition Mark V parts have been added and training completed
- OEM supplementary support agreements have been in place for turbovisory.
- No recent issues causing outages.

8.2.8.5 Actions

No major actions/changes to existing systems, based on the Condition Assessment, are recommended.

- Maintain existing systems – maintaining/supplementing spares, securing maintenance agreements with OEM's on Mark V governor and turbovisory and switchgear. Replace as required.
- Continue inspections/testing.

The need for additional actions should be investigated/re-examined about every five years, especially if the normal mode of plant operation should be modified to extend beyond March 2023. Obsolescence and an inability to obtain parts may necessitate some replacements or refurbishments, less likely an overall cost benefit assessment due to reduction due to reduced maintenance costs on newer equipment. Generally, one synch condenser operation would indicate that stage 1 gear be operated on a to failure and replace basis. Three running units in stand-by would likely require upgrades or replacements in the next five years justified primarily due to obsolescence and no spare parts availability. In-Service Failure funding may be applicable in some cases.

8.2.8.6 Risk Assessment

The Risk Assessment associated with the system had no High Risks, both from a technological perspective and a safety perspective, in the 2011 and 2017 update report. The Risks are little changed in 2019.

- Switchgear, turbovisory, Mark V governor systems remain significant risk areas, medium at this point in time, given offset by sparing and management strategies undertaken by the plant. (Ideally replacement would be desirable, but financially infeasible given remaining life).
- OEM support may grow more difficult to obtain

There is a likelihood that some older items may fail in service, but PM work and redundancy should minimize impacts. A further review of specific critical equipment over the next few years is likely needed if the units are to continue in standby operation after March 2023.

8.2.8.7 Life Cycle Curve and Remaining Life

The "Risk Area" in that Figure has not significantly changed.

The Unit 1 Control Systems (including DCS) Associated with Steam Systems are considered able to reach the March 2023 end of life normal generation mode end date, and 2027 emergency/standby mode date for generation, provided regular inspection and service per the station PM plan is maintained. Obsolescence and spare parts unavailability may necessitate some unforeseen equipment replacements/refurbishments.

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, there is no incremental Level 2 inspection requirement, provided the current inspection and maintenance program for the system is maintained.

8.2.8.9 Capital Projects

The suggested typical capital enhancements for the system would include minor costs for continued critical control card spares procurement. No major capital is considered justified given limited life and generation level, unless identified by regular PM inspections or during exercising operations. Utilization of In-service Failure funding may be warranted where applicable.

8.2.9 Asset 271309 – Unit 1 Steam Turbine (Chapter 8.2.9 in 2011 Report)

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

8.2.9.1 Description (No major change since 2010/11 and 2017 update Reports)

8.2.9.2 History (No Major Change Since 2017 Update Report)

On January 11, 2013 some of bearings were wiped and journals damaged. Journals and bearings resized as part of restoration work.

8.2.9.3 Inspection and Repair History (No Major Change Since 2017 Update Report)

A turbine overhaul was undertaken in 2012. The turbine major overhauls are now scheduled on a 9-year frequency (generator every six years) with a turbine valves overhaul frequency of 3 years. The HP turbine section nozzle block was replaced in 2009.

An overhaul was undertaken in 2014 as result of 2013 failure. The #1 bearing was reworked in 2014 as a result of the 2013 failure.

In 2018, the GE Major U1 Turbine Valve Outage Report Jul-Oct 2018 indicated.

The work scope included:

1. Disassemble, clean and inspect, and reassemble all 6 control valves
2. Disassemble, clean and inspect, and reassemble main stop valve
3. Disassemble, clean and inspect, and reassemble both combined reheat valves
4. Disassemble, clean and inspect, and reassemble blowdown valve
5. Disassemble, clean and inspect, and reassemble all 7 non-return valves
6. Disassemble, clean and inspect, and reassemble T2 oil deflectors
7. Inspect turning gear

All inspections and repair/replacements completed successfully.

Steam Turbine Inspection History and Projection

T Turbine
G Generator
V Turbine Control Valves

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit #1			T/G/V			V			G/V			T/V			G/V			V
Unit #2		V			T/G/V			V			G/V			T/V			G/V	
Unit #3	V			V			T/G/V			V			G/V			T/V		

Generator O/H seperated from turbine and changed to 6yr cycle

8.2.9.4 Condition Assessment

The 2013 issues with the Unit 1 steam turbine lube oil system resulted in damage that was repaired. Nevertheless, it has left the turbine sensitive to vibration during start-ups, requiring a longer start-up period requiring more care. There is a suggestion that GE didn't encounter the vibration during one test and that it may be possible to reduce/eliminate it in another way.

8.2.9.5 Actions

Based on the condition assessment, no major additional actions are recommended. PM's and planned inspections should be undertaken. Previous recommendations in the 2010/11 Condition Assessment and 2017 Update Report should be followed where practical given the remaining life. Further testing and analysis should be undertaken in an effort to eliminate the vibration from an equipment health and start up time perspective.

8.2.9.6 Risk Assessment

The risk assessment associated with the system, both from a technological perspective and a safety perspective, is that there is no major risk provided ongoing inspections and PM's are followed.

8.2.9.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change is that the yellowed "Risk Areas" will have shifted towards the 2025+ timeframe range.

8.2.9.8 Level 2 Inspections – Unit 1 Steam Turbine

A turbine/valve inspection overhaul planned for 2021 is considered warranted. Given the condition historical data reviewed, the outage should include Level 2 analyses:

- stud (for those above 850oF) creep life assessment

- LP L0 borescope
- Assess and test options to eliminate vibration issues

Thereafter, undertake these consistent with 30,000 equivalent operating hours (max 12 years) for steam turbine and 12,000 equivalent operating hours (max 8 years) for valves.

8.2.9.9 Capital Projects

No major capital is considered justified given limited life and generation level. The 2021 inspection/overhaul of turbine valves and steam turbine is warranted, particularly the valve overhaul if normal life is extended to 2023. If normal life is not extended to 2023 and the units are operated in cold standby/emergency mode post steam, it should be considered for the 2023 to 2025 period. In a post steam, cold standby/emergency period it is suggested they be repeated every 30,000 equivalent operating hours for the steam turbine (Maximum 12 years), 20,000 equivalent operating hours for generator (10 years maximum) , and 12,000 equivalent operating hours for the valves (maximum 8 years).

8.2.10 Asset 270182 – Unit 1 Cooling Water System - Associated with Steam Systems

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 (No major change since 2010/11 and 2017 update reports)

8.2.10.2 History (No major change since 2010/11 and 2017 update reports)

8.2.10.3 Inspection and Repair History

<u>Cooling Water Pumps & Motors, Screens, and Piping Systems</u>

CW Travelling Screens

Interviews suggest that no recent issues have been experienced with this unit. Visual examination confirms that generally the Unit 1 screens appear in reasonably good shape. 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 well. No recent reports (U1 CW West Sep 2010/11 repair) were identified on the condition of the pumps, but discussions suggest that regular maintenance has been ongoing and the unit should be able to meet March 2021 end of life timelines with continued maintenance. Major pump overhauls are scheduled on a twelve-year cycle as indicated in the chart below from the 2011 report.

Major Pump History & projections Unit 1 (k$)

														Post Steam (projected)								
Mean time between O/H	Pumps	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12yr	1 CW Pump East					77												230				
12yr	1 CW Pump West	75												200								
12yr	1 Ext Pump North			~~79~~			92												200			
12yr	1 Ext Pump South					92												175				
	1 Vac Pump North	25												75								
	1 Vac Pump South					~~x~~										75						
6yr	1 BF Pump East						140						250						300			
6yr	1 BF Pump West	160						190						250						300		

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 appear to continue to be in good condition but remain 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 appears little changed.

Cooling Water System Intake & Discharge

PM inspections are generally on a three-year cycle as per schedule taken from the 2011 report below. in No indication was provided that the 91 cm (36 inch) and 162 cm (64 inch) CW intake and discharge concrete piping installed underground to the unit condenser has any obvious issues with the systems, but no detailed engineering evaluations and NDE work could be identified to have been undertaken.

A visual was done in 2016/17. An inspection of the CW sump, intake and outfall, and intake and outfall piping are planned in 2020. Attention will be required the exposed concrete support in the East Sump pit that has experienced significant concrete loss and exposed the lower layer of reinforcing bars.

8.2.10.4 Condition Assessment

CW condenser intakes were replaced since 2011. There appear to be no significant issues with the system (except the concrete beam degradation noted in Sump 1 East), provided inspections and when testing programs, and PM's are undertaken.

8.2.10.5 Actions

Based on the Condition Assessment, the following Actions are recommended:

- Continue concrete intake and discharge pipe inspections – next planned for 2020
- Continue pump/motor inspection PM's
- Maintain critical pump motor parts (coils) available

8.2.10.6 Risk Assessment

The Risk Assessment associated with the system showed no high-risk level issues in of the 2011 C.A and 2017 updated reports. Currently, that assessment remains valid, with no high-risk issues, provided PM's and inspection schedule maintained.

8.2.10.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" will have shifted towards the 2025+ timeframe range.

8.2.10.8 Level 2 Inspections – Unit 1 Cooling Water System Associated with Steam Systems

A Level 2 analyses of the CW sumps and pipes was planned as part of a larger overall Level 2 inspection project in 2020 that has since been cancelled. Given the condition historical data reviewed, the current inspection and maintenance program for the system should be maintained. Further checks on the concrete support beam in the sump are warranted.

8.2.10.9 Capital Projects

No additional capital projects are anticipated, if spare CW pump and motor critical parts are available readily

8.2.11 Large Motors (4 kV) (Added here in 2017 Condition Assessment Updated)

8.2.11.1 Description

The following is a description of the major 4 kV motors in each of the three units. The information provided indicates that in one instance the same motor is installed in two different units (i.e. Units 1 and 2). In addition, the same serial number is applied to two different motors in Units 2 and 3, which cannot be correct. These will require verifying the serial numbers and the data below.

Unit 1 Motors

- Boiler Feed Pump (BFP) Motor – East (SN – SP23971) ABB, 3-phase, 4160 volt, 3000 HP, 60 Hz, 3583 rpm
- Boiler Feed Pump (BFP) Motor – West (SN – 6254AA-01) Westinghouse, 3-phase, 4160 volt, 3000 HP, 60 Hz, 3580 rpm
- Cooling Water Pump (CWP) Motor – East (SN – 9-132171-1) Tamper, 3-phase, 4000 volt, 300 HP, 60 Hz, 590 rpm
- Cooling Water Pump (CWP) Motor – West (SN – 9-132171-3) Tamper, 3-phase, 4000 volt, 300 HP, 60 Hz, 590 rpm
- Condensate Extraction Pump (CEP) Motor – North (SN – D06 99071360-0018-01 NRR) US Motor, 3-phase, 4160 volt, 400 HP, 60 Hz, 1780 rpm
- Condensate Extraction Pump (CEP) Motor – South (SN – 695085/1) US Motor, 3-phase, 4160 volt, 400 HP, 60 Hz, 1780 rpm
- Forced Draft Fan (FDF) Motor – East (SN – 4542361) ABB, 3-phase, 4160 volt, 1502 HP, 60 Hz, 1189 rpm
- Forced Draft Fan (FDF) Motor – West (SN – 4542362) ABB, 3-phase, 4160 volt, 1502 HP, 60 Hz, 1189 rpm

Spare Motors

- The following spare motors were purchased in 2013

Note: All spare motors are kept in a Pennecon warehouse.

Units 1 and 2

- 2 Boiler Feed Pump (BFP) Motors SCIM, sin# 1026366788, frame MGP500B 3-phase, 4160 volt, 3000 HP, 60 Hz
- 1 Forced Draft Fan (FDF) Motor SCIM, sin# 1026842643, frame MGP500C 3-phase, 4160 volt, 1500 HP, 60 Hz, 1189 rpm

8.2.11.2 History – None included

For Units 1 and 2, new motors were installed for the CEP, FDF, and BFP's in 1989.

The changes since the 2010/11 report are:

- Purchase Spare 4kV Motor (shared Units 1 and 2)
- Installation of Variable Speed Drives on FD Fans
- Overhaul Extraction Pump Motors
- Overhaul FD Fan Motors
- Overhaul CW Pump Motors

8.2.11.3 Inspection & Repair History

Maintenance is carried out on the 4,160 V motors during annual unit outages, in the form of Megger and Bridge tests, air filter changes, and oil sampling and analysis. At the same time there is on-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pennecon rotate spare and megger annually.

The following illustrates items that incurred significant expenditures for maintenance and failures.

Year	Description of Expenditure	Type	U1	U2	U3	Spare
2013	Purchase Spare 4kV Motors	CI	x	x	X	x
2014	Install Variable Speed Drives on Unit #3 FD Fans	CI			X	
	Overhaul West FD Fan Motor, Unit #3	SME			X	
	Overhaul/Rewind East FD Fan Motor, Unit #3	MF			X	
	Overhaul North Extraction Pump Motor, Unit #3	SME			X	
	Overhaul Unit 2 South Extraction Pump Motor	SME		x		
	Overhaul Unit #2 East FD Fan Motor	SME		x		
	Overhaul Unit #1 South Extraction Pump Motor	SME	x			
	Overhaul Unit #1 West FD Fan Motor	SME	x			
	Overhaul Unit #1 East CW Pump Motor	SME	x			
	Install Variable Speed Drives on Unit #1 FD Fans	CI	x			
2015	Install Variable Speed Drives on Unit #2 FD Fans	CI		x		
	Overhaul Unit #2 West FD Fan Motor	SME		x		
	Overhaul Unit #1 East FD Fan Motor	SME	x			
	Overhaul/Rewind Unit #3 East CW Pump Motor	MF			X	
	Overhaul Unit #3 West CW Pump Motor	SME			X	
2016	Overhaul Unit #2 East CW Pump Motor	SME		x		
	Overhaul Unit #1 West Boiler Feed Pump Motor	SME	x			

CI = Capital Investment

SME = Significant Maintenance Expenditure

MF = Major Failure

8.2.11.4 Condition Assessment

The typical life of a 4 kV motor is about 25 to 30 years of operation with regular maintenance carried out. Holyrood typically consider historic levels equivalent to roughly 40 to 50 years of operation. If the motors are being 2 shifted, that causes advanced aging from thermal cycling. The best type of operation for a motor is continuous on-line operation with minimal start/stops.

Given its operating pattern and start/stop history, it may be that Holyrood units have only accumulated 25 to 30 years of operation over the 48 calendar years. AMEC Report No. P164200 / RP / 001 - June 2015, HTGS Condition

Assessment and Life Extension Study, Report – 4 kV Motor Condition Assessment presents the service life expectation for the 4 kV motors for Units 1, 2 and 3:

- CWP - Cooling Water Pumps - expected life to 2023+
- CEP - Condensate Extraction Pumps - expected life almost to 2030
- FDF - Forced Draft Fans - expected life almost to 2030
- BFP - Boiler Feed Pump - expected life almost to 2030

8.2.11.5 Actions

Based on the Condition Assessment, the following Actions are recommended.

- Continue to inspect and monitor motor condition and undertake regular maintenance and PM's

8.2.11.6 Risk Assessment/Life Cycle/Remaining Life

For Units 1 and 2, new motors were installed for the CEP, FDF, and BFP's in 1989. It is expected that with annual inspections and maintenance, they should have no issue reaching March 2023 or beyond, since they will only have done roughly 30 years of operation.

The cooling water (CWP) pump motors in Units 1 and 2 are original equipment but are expected to meet a March 2023 target based on (AMEC Report No. P164200 / RP / 001).

There was a recommendation that a spare motor to meet the needs of the CWP and CEP might be warranted. The CEP motors of Units 1 and 2 will be in the 30-year range of operation at 2021, so they are expected to achieve the target end date. The CWP motors are already beyond 40 years and could be at risk of not achieving the end date of March 2023 without some operational issues or a failure. Spare coils and bearings were purchased for the CW pump motors (A spare CWP motor expenditure would not be cost effective for only 3.5 remaining years of life)

There was also in 2011 a recommendation to consider fluid couplings or install variable speed drives on the BFP and FDF motors. This was not carried out for the BFP motors, but variable speed drives were installed as a Capital Expenditure on the FDF motors of all three units during overhauls in 2014 and 2015.

8.2.11.7 Level 2 Inspections

Given the condition historical data reviewed, no Level 2 analyses are required provided the current inspection and maintenance program for the system is maintained.

8.2.11.8 Capital Projects

No additional capital projects are required. The failure of one of the CEP motors on Units 1 and 2 would cause an extended outage/derate, however, the likelihood of a failure of one of these is considered low to medium based on the existing condition and number of operating years being under 30 at this time.

9. Unit 2

9.1 Unit 2 – Key Systems

9.1.1 Asset 7753 – Unit 2 Generator

Equipment/components covered in this report are:

Unit #:	**2**
Asset Class #	BU 1296 - Assets Generations
SCI & System:	7638 - #2 Turbine & Generator
Sub-Systems:	7753 # 2Generator Assembly
Components:	775 4 #2 Generator Rotor
	7759 #2 Generator Stator
	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 2016. This 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, employed at each end of the generator, prevent the hydrogen from escaping around the rotating shaft. The seals are mounted in the casing end-shields, located inboard of the bearings, and pressurized by oil. The rotor (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.

Since the original excitation equipment moved to its obsolete phase of its life cycle, the exciter has been partially upgraded. The power section and field breaker were reused, and the controls upgraded to Unitrols 6080 platform. 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.

Machine Type	Turbine-Generator	RPM	3600
Voltage / pf	16 kV / 0.9	Manufacturer	GE
KVA	194,445	Date Manufactured	1970

Insulation Class	B	Serial Number	980486
Cooling	Hydrogen @ 45 psig	Slots / Circuits	66 / 2

The stator core and winding are directly hydrogen cooled; the rotor has a directly hydrogen cooled winding, sub slot supply and radial discharge through the winding.

The auxiliary systems include:

- The controls in November 2017 upgraded to the Unitrol 6080 platform,
- 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; The PT's primary and secondary fuses are checked on the regular base. There is a spare PT in 2019 on site, CT's are in good condition and are checked every 6 months.
- 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 shutdown. 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. It also provides supplementary alarms and sequence-of-events monitoring. Bently Nevada upgrades were completed on all units.

9.1.1.2 History (No major change since 201/2011 Report and 2017 update)

9.1.1.3 Inspection and Repair History (no major change since 2017 update)

In 2014, Alstom were on site for Unit 2 maintenance inspections and testing. Testing consisted of a visual inspection of the stator winding and end winding structure, an EL-CID test of the core, stator winding wedge tap test, insulation resistance, polarization index, high voltage dc ramp test and a stator winding low voltage resistance test. They produced a report (#FSRG025106), which covers a comprehensive series of tests, visual inspections and maintenance of the stator and rotor.

There are no generic or specific design and manufacturing deficiencies identified from the 2014 Alstom testing reports. Wedge tightness testing showed minimal loosening of the slot wedging system since re-wedging in 2005. At the 2005 overhaul, the generator was fitted with top ripple springs. As of 2014, the windings were still tight and re-wedging is not likely required at this time. The insulation resistance (IR) and Polarization Index (PI) values indicate acceptable condition of the rotor winding insulation.

Recurrent surge oscillography (RSO) testing of unit 2 field winding showed that no turn shorts existed at standstill.

No indication of overheated insulation has been identified on visual inspection. Unit 2 is reported to operate at relatively low temperatures. Overheating damage is likely to create ground-wall insulation delamination, resulting in detectable increase in partial discharges. PD testing does not indicate this condition.

Winding contamination is not an issue and has been confirmed by generator inspections in previous overhauls. Surface discharges can be identified by PD monitoring.

End-winding vibration is a recognized generic problem on a most GE generators, particularly 2-pole machines. The main reason is an end-winding natural frequency too close to the 120 Hz, twice per rev frequency. Relaxation in service causes a shift of the natural vibration frequencies of the end winding support system to decay closer to the forcing frequency at 120 Hz. The increased vibrations result in rubbing and abrasion of the bar insulation at support interfaces. Although some end winding relaxation has been noted on this generator, the supports have been stiffened during past overhauls. The Unit 2 report from 2014 indicates some minor insulation dusting from vibration induced winding motion. It cannot be predicted if further relaxation may occur, causing winding damage. End winding vibration monitoring can be effective for detection of changes in vibration levels and indicate the need for corrective maintenance. It is unknown if this problem will return prior to 2021, but it is considered a low probability that any deterioration would be significant enough to hinder operation out to 2021.

In 2016, the excitation transformer was replaced. The lead of the excitation transformer was changed to flexible lead. In November 2017, the Excitation system controls were upgraded to the Unitrol 6080 platform.

In 2017 Valve Minor Inspection Report by GE, a new DC lube oil panel was installed, and RSO testing and standard generator electrical tests were carried out. All test results were satisfactory.

In 2017 Holyrood Rotor RSO Field Service Report CFSR28102017, a rotor Recurrent Surge Oscillograph (RSO) was conducted in October 2017 and identified no shorts in rotor at 3600 rpm. Other tests included:

Stator:
- Power Factor Tip-Up as per IEEE 286 (latest)
- Insulation resistance (5000 VDC) on each phase
- Polarization index (5000 VDC) on each phase
- DLRO (winding resistance test)
- DC Leakage
- Installation of DC starter lube oil panels installation

Exciter:
- RSO Test – at rest

Field:
- Insulation resistance (500 VDC)
- Polarization index (500 VDC)
- DLRO (winding resistance test)
- AC Impedance

Results were acceptable.

In 2017, the visual inspection did not report any significant degradation in the stator or rotor windings insulation or mechanical damage. Only minor surface contamination and small surface corona marks in the end winding areas were reported. Some dusting and greasing in the endwinding overhang area was also noted.

The Insulation Resistance (IR) of the stator winding was tested at 5000 VDC and found to be in the 3 to 4 G-ohm range. The Polarization Index (PI) was found to be approximately 5. A controlled dc overvoltage test (DC Ramp) up to 27 kV was also performed and no anomalies were found. There was no maintenance high potential (Hi-Pot) test carried out. Overall, the stator winding insulation appears to be in good condition for its age.

The stator wedge tightness testing did not indicate any appreciable relaxation in wedge tightness since re-wedging in 2005. All end wedges also appear to be tight. The winding in slot section of the core is mechanically stable; thus, there is low probability of bar vibration and insulation abrasion even though this is one of the most likely deterioration processes in this type of stator.

The core El-Cid test result is well within acceptable range, including the step iron packets and does not indicate any inter-laminar damage. Visual inspection of the stator bore and back of core areas did not reveal any anomalies. Core degradation is not expected in the period out to 2023 to normal generating mode for 2027 emergency/standby mode.

The results of rotor winding insulation resistance on Unit 2 are acceptable. There is no apparent reason based on the evidence from the 2014 test reports to conclude that there is a need for a major rotor upgrade, such as a rewind of the rotor. The 2017 rotor winding resistance was measured to be 414 M-ohms at 500 V dc at one minute with a PI of 1.18. This is a value lower than one would normally expect and is indicative of moisture or contamination being present. The Alstom service report notes that this value of insulation resistance is "very low". However, other than some general cleaning of the rotor body and underneath the retaining rings, no other action to increase the insulation resistance readings was taken at this time. Reliable service to 2023 appears to be a reasonable expectation. Application of rotor shorted turn detectors (flux probes) would provide additional assurance that any future turn shorts would be reliably detected and repaired as required. Any sudden increase of bearing vibration may indicate the presence of shorted turns in the rotor winding. A 2017 recurrent surge test (RSO) was performed on the rotor windings and no deviations of the pulse outputs were observed. This result indicates that no shorted turns were present on the rotor at standstill. Bearing vibration should continue to be closely monitored.

Previous visual inspections of the retaining rings and forging did not reveal any evidence of overheating or electrical discharges from the rings to the slot wedges. Such indications would be expected if the rotor was subjected to excessive negative sequence currents. The 2017 rotor visual inspection was done without the retaining rings removed and thus limited access provides only a cursory assessment. Regardless, there were no obvious issues reported. The rings and forging appear sound and suitable for service to 2023.

On-line PD tests did not reveal any serious thermal deterioration of the ground-wall insulation or mechanical damage to the surface stress relief coatings due to movement of bars in the slot. Reliable stator winding insulation life to 2027 is therefore probable. The on-line testing frequency of twice a year should continue, to detect any unexpected and rapid rise in PD magnitudes indicating insulation degradation.

The report recommended planning and executing a standard set of generator field, stator and exciter electrical test at next scheduled outage (2023?).

T Turbine
G Generator
V Turbine Control Valves

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Unit #1			T/G/V			V			G/V			T/V			G/V			V			T/G/V
Unit #2		V			T/G/V			V			G/V			T/V			G/V			V	
Unit #3	V			V			T/G/V			V			G/V			T/V			G/V		

In 2017 Generator O/H seperated from turbine and changed to 6 yr cycle

9.1.1.4 Condition Assessment

The generator is scheduled to operate out to 2023 in normal generating mode, and emergency/standby mode to 2027+. The generator has accumulated roughly 200,000 (192,000) hours of service life and about 550 starts in 49 years of operation. In recent times, Unit 2 runs about 50 percent of the time and generally well below name plate rating. Operating at lower load reduces the temperature effects of aging on the rotor and stator winding insulation.

The generator, exciter, and auxiliary systems are in reasonably good condition for their age. Based on changes and the testing/inspection results on the generator, there are no issues expected to limit the normal operation mode life before March 2023, or the emergency/standby mode to 2027+. Earlier, it had been considered to have a stator rewind in the 2021 to 2023 period, but this is unlikely to be economic or necessary.

The machine, both stator and rotor, have a high probability of making it to 2023 with only the normal maintenance. Beyond that, major refurbishments such as rewinds need only to be considered if significant usage during 2023 to 2027 or beyond period is to be considered. Once the unit enters its standby/emergency role, it is likely that major inspections would only be required every 10 years, subject to any extensive period of use or issues that arise during exercising operation or any online monitoring issues.

9.1.1.5 Actions

Given the Overhaul and testing information and results, the primary actions are:

- Continue the generator testing and inspections (next is in 2020), but every 20,000 equivalent hours (maximum 10 years) as conditions warrant to verify condition (stator Doble test measurements during the summer outage - necessary to disconnect the neutral bar);
- Continue regular planned/predictive maintenance activities on various generator auxiliaries (hydrogen, oil systems, cooling systems, etc.)
- Monitor the stator 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.
- Check the hydrogen consumption and seal oil consumption for leakage (GE recommends seal oil supply piping flushed annually, to prevent dirt in the emergency by-pass line entering the system);
- Take stator Doble test measurements every 3 years to 2023 and every 6 years thereafter as conditions warrant during the summer outage (it is necessary to disconnect the neutral bar)

No rewinds are required. No action was taken on significant risk related to retaining rings – none warranted at this time given the remaining life.

9.1.1.6 Risk Assessment

The high-risk elements of the Risk Assessment of the 2010/11 Condition Assessment and 2017 update report for the Unit 2 Generator and auxiliaries and exciter have largely been dealt with.

Stator windings are generally of the most concern for long term reliable operation in the stator portion of the generator. Global deterioration of the Unit 2 stator winding insulation is not indicated from recent inspections and test reports. Future degradation cannot be reliably assessed, and the end of winding life cannot be predicted, especially if operating events are encountered. However, given the present condition of the stator winding, a stator rewind should not be required over the next 3 years to the end of 2023. It is assumed that any gradual winding deterioration in normal service will be detected by condition monitoring and the condition restored by preventive and corrective maintenance. Normal monitoring, inspection, testing (i.e. on-line PD) and maintenance should allow operation out to 2027+.

The condition of the rotor also appears to be sound based on recent inspections and testing. The rotor does not require any major remedial work such as rewind or re-insulation, based on the evidence presented. Normal monitoring and maintenance should allow operation.

Further, it should be noted that this assessment is valid for normal expected unit service. The consequences of abnormal operation or unpredictable system stress events cannot be predicted.

9.1.1.7 Life Cycle and Remaining Life

The unit is in good condition to achieve a 2023 normal mode of generation life and 2027 emergency/standby mode Again, it should be noted that this assessment is valid for normal expected unit service. The consequences of abnormal operation or unpredictable system stress events cannot be predicted.

With the 2017 changes to the exciter controls and transformer, this system will also be in good position of meeting a 2023 normal mode of generation life date, with continued PM work and inspections/testing.
The hydrogen system should be in good position of meeting a 2023 normal mode of generation end of life date, with continued PM work.

Essentially work on the units has shifted the yellow Risk boxes in those figures further out in time.

9.1.1.8 Level 2 Inspections – Unit 2 Generator

A generator inspection is planned in 2020. No other Level 2 analyses are specifically required given their current condition and their ability to make a 2023 normal mode of generation end of life date, provided that the plant maintains their current maintenance and inspection programs, including annual megger tests and hydrogen seals checks. Inspections in 2020 and every 20,000 equivalent operating hours thereafter (ten years Maximum) should be considered, based on operating conditions and PD results analysis.

9.1.1.9 Capital Projects (Exciter controls completed in 2017)

No capital projects are recommended, beyond the currently planned generator inspection in 2020.

9.1.2 Asset 7711 – Unit 2 Generator Lube Oil System

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 7715 #2 Purification 7720 #2 Pump South 7721 #2 Pump North 7725 #2 DC Pump 7743 #2 Hydraulic Oil Pump North 7744 #2 Hydraulic Oil Pump South

9.1.2.1 Description (No major change since 2010/11 Report and 2017 update)

9.1.2.2 History (No major change since 2010/11 Report and 2017 update)

9.1.2.3 Inspection and Repair History (No major change since 2010/11 Report and 2017 update)

As a result of Unit 1 Lube oil system failure in 2013 resulting in significant Unit 1 Steam Turbine damage, the Unit 2 AC Lube oil pump motors and overhauled DC lube oil pump motor. In the 2017 Valve Minor Inspection report, it was noted that the DC lube oil panel were replaced in 2017.

9.1.2.4 Condition Assessment

This system has been in service since the unit 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 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 frames required.

All parts of the generator lube oil system are expected to be able to meet the generation end of normal generation life of 2023, and in cold standby/emergency mode to 2027+, assuming their regular maintenance inspections and work are followed through on.

9.1.2.5 Actions

Based on its overall condition assessment, no changes to the 2010/11 C.A and 2017 Update Recommended Actions are recommended. Maintaining the ongoing PM program inspections and practices for the lube oil system are most critical.

Assess the requirements for and impacts of quicker start requirements on heater system temperatures in 40-45 °C range.

9.1.2.6 Risk Assessment

All the risk items of the 2010/11 Condition Assessment report remain as Low Risk, both from a technological perspective and a safety perspective, provided ongoing regular inspections and maintenance PM's are followed and issues similar to 2013 Lube Oil system failure on Unit 1 addressed.

A maintenance strategy will be required for beyond March 2023 regarding turning gear and motor PM maintenance requirements.

9.1.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025+ timeframe range.

9.1.2.8 Level 2 Inspections – Unit 2 Generator Lube Oil System

Given the condition historical data reviewed, no Level 2 analysis of the lube oil system is recommended, provided the current inspection and maintenance program for the system is maintained.

9.1.2.9 Capital Projects

No significant capital enhancements for the system are recommended. Maintenance repairs and minor capital replacements found during inspections should suffice to achieve the March 2023 normal operation and 2027+ standby/emergency generation end dates.

9.1.3 Asset 8152 – Unit 2 Electrical & Control Systems Associated with Generators

The requirements for the electrical & 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:	7677 #2 Turbine Governor System 8138 #2 Relay Room Protection & Control 8144 #2 Main Controls

	8153 #2 Generator Bus-Duct and Connections 8173 #2 Battery Chargers 8174 #2 UPS2 Inverter 8186 #2 Battery Banks 271478 #2 Switchgear 4160V/600V 8162 Power Centre "B" UAB2, (600V) 271479 #2 Turbine Supervisory System 299451 #2 DCS

9.1.3.1 Description (No major change since 2010/11 Report and 2017 update)

Asset 7677, Unit 2 Main Controls/Turbine Governor System

- The system is comprised of an electronic speed governor, (GE SpeedTronic Mark V), manufactured by General Electric, and installed in 1999. The governor is complete with protection and monitors speed, metal temperatures, vibration and steam valve positions into the turbine. An HMI for operator use is provided in the control room. The end of life of Mark V turbine control system was originally 2013. Its firmware was upgraded in 2015. Additional OEM support and spare cards have been implemented.
- U2 DC Panel was upgraded in 2015. Also, some generator protection Schweitzer) and stator gound fault alarms.

Asset 8173, Unit 2 Battery Chargers (Typically 20 Years)

- 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, max. 200A Charger rated maximum 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, c/w Westinghouse breakers. Unit one 250VDC Panel Board was manufactured by Eaton, installed in July 2014 and is a type Pow-R-Line 4

258VDC Unit 1 and Unit 2 battery chargers were replaced in 2019. 129 VDC battery chargers were replaced previously.

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, 3ph 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, 3ph, 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, 3ph, 4W, 225A, 42 circuit, 100A main breaker, branch breakers type BQ, and was installed in 1998.

9.1.3.2 History (No major change since 2010/11 C.A and 2017 update)

9.1.3.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update)

UPS #1 and #2 life are planned to be extended by re-using parts from UPS #3 and #4 that are planned to be replaced in 2020. Further short-term actions are planned to be considered thereafter.

9.1.3.4 Condition Assessment (No major change since 2010/11 C.A and 2017 update)

The basic DCS, protections, alarms associated with generators and auxiliaries are in fair shape but will need to be re-examined about every five years or so, and if the normal mode of plant operation should be modified to extend beyond March 2023. The 4160v and 600v switchgear equipment appears to be reasonably reliable for the 2023 end of steam life, as long as proper maintenance as scheduled. A short term review should be undertaken of the motor controls, relays/switchgear, and some auxiliary systems such as hydrogen monitoring and generator temperature monitoring regarding replacement or refurbishing, primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment.

If post steam (2021, 2022, or 2023) only one synch condenser operation was needed, then that most stage 1 gear would largely be run on an end of practical life where required basis. Some of the Stage 1 4160 V gear is required for reliability and considering safety. For three running units in stand-by, some more extensive upgrades/refurbishments or replacements will be needed over the next five years.

For stage 1, post steam (2021, 2022, or 2023) the plant have indicated a potential need for the 4160v station board SB12 c/w associated breakers – depending on whether it is needed to keep the station service feed from the terminal station into the plant as well as the black start diesels and overhead line into SB12 (tranfer bus through SSB4 to TB12 - SB34; SSB3 kept to feed through AT-C down to C1 and Power Center C; Power Center C in its entirety; both diesel buses). This would apparently require at least 14 electrical distribution breakers to have to remain in service. Given the current state and age of the equipment, some significant capital for refurbishment/replacement is likely (requires cost/benefit analysis).

For post steam standby role, Stage 1 refurbishment/replacement is indicated to include at least twenty-six 4160Vac breakers - 10 for unit motor feeds, 16 for electrical distribution. A more detailed analysis and obsolescence/cost/benefit analysis would be needed.

9.1.3.5 Actions – Unit 2 Electrical and Control Systems

Modest additional actions beyond those in the 2010/11 Condition Assessment and 2017 update report are recommended for the electrical and control systems, provided maintenance and PM work continues and component issues identified are resolved. Some issues that should be examined are:

- Continue PM on battery and chargers. Assess need to undertake battery replacements.
- Maintain OEM support and spare parts, governor, and supervisory systems.
- Investigated/re-examine the need for additional actions about every five years or so, and if the normal mode of plant operation should be modified to extend beyond March 2023.
- Review the motor controls, relays/switchgear, and some auxiliary systems regarding replacement or refurbishing, primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment.
  - Stage 1 needs for one-unit synchronous condensing role only post steam, including need to keep the station service feed from the terminal station into the plant as well as the black start diesels and overhead line into SB12
  - Stage 1 operating requirements for cold standby/emergency mode post 2023, based on obsolescence and cost/benefit impact on reliability and maintenance costs

9.1.3.6 Risk Assessment

Overall, the ratings in the 2010/11 Condition Assessment and 2017 update report have not changed, provided PM work continues and issues identified addressed. Most were either low or medium risk, although Stage 1 equipment obsolescence and spare part availability is of concern.

The safety high risk items were the Gen Bus Duct (med/high) and the Blr/Turb MCC C2 C3 (med/high). These likely have not changed, but should be reviewed, as well as critical switchgear,

There is a likelihood that some older items may fail in service, but PM work and redundancy should minimize impacts. A further review of specific Stage 1 critical equipment needs and condition and refurbishment or replacements needs over the next five years is needed for a) the one synchronous condenser unit case; and b) if all three units are to continue in cold standby/emergency operation mode after March 2023.

9.1.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards 2023+ timeframe range for normal operation, although Stage 1 equipment obsolescence and spare part availability is the immediate situation of concern.

9.1.3.8 Level 2 Inspections – Unit 2 Electrical & Control Systems Associated with Generators

No Level 2 analyses are currently recommended. Spot checks critical equipment over the next few years, including on:

- Bus Duct – inspection and test (no indication done since 2011; may have been done in 2018)
- Power Centre B, AAB2 – inspection and testing (no indication done since 2011)
- Cables – inspection and testing (no indication done since 2011)

An assessment of Stage 1 equipment is needed for a) the one synchronous condenser unit case; and b) if all three units are to continue in cold standby/emergency operation mode after March 2023.

9.1.3.9 Capital Projects

Given the end of generation life normal mode of March 2023, no further immediate capital enhancements for Unit 1 Electrical & Control Systems Associated with Generators are recommended, unless identified by regular PM inspections or during exercising operations or during the assessment of needs and condition identified previously. Utilization of In-service Failure funding may be warranted where applicable for some short-term issues. Capital for longer term refurbishments/replacements of Stage 1 equipment cannot be committed to until the needs are clear, and a cost/benefit analysis undertaken.

9.1.4 Asset 271486 – Unit 2 Cooling Water Systems Associated with Generators

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

9.1.4.1 Description (Minimal Change since 2010/11 Report and 2017 update)

9.1.4.2 History (Minimal Change since 2010/11 Report and 2017 update)

9.1.4.3 Inspection and Repair History (Minimal Change since 2010/11 and 2017 update Report)

CW Travelling Screens

Travelling screen internals were overhauled in 2015/16. No issues have been experienced with these units. The external casings are in differing states, with some parts more corroded than others. None appears to impair current or short-term performance. Civil floor issues in Pumphouse #1 were investigated in 2017. The 3rd party review indicated no issues with Unit #2 and requirement prior to 2021).

CW Pumps

The west CW pump was overhauled in 2011 and the east CW pump and motor was overhauled in 2016. Both are performing fairly well. No reports of issues. The units should be able to meet March 2021 generation end of life with continued maintenance. Major pump overhauls are scheduled on a twelve-year cycle.

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. There have been no obvious issues with the systems, but no detailed engineering evaluations and no NDE work has been undertaken – no indication that PM inspections planned on a three-year cycle in 2015 were undertaken. It is planned to do level 2 inspections in 2020 of: the intake and outfall structure; the pumphouse and outfall sumps; and the pipes to and from the unit and to the outfall.

9.1.4.4 Condition Assessment

Condition Assessments have not changed substantially since 2010/11 C.A and 2017 update Report. The systems can likely be made to function satisfactorily for March 2023 generation end of life. (Concern with the Stage 1 pumphouse civil issues with the floor were examined in 2017 and no action expected for Unit 2 to be required for 2021 end of life). It is planned to do level 2 inspections in 2020 of: the intake and outfall structure; the pumphouse and outfall sumps; and the pipes to and from the unit and to the outfall.

9.1.4.5 Actions

The actions identified in the 2010/11 Condition Assessment (Table 9-23) largely still apply, and include:

- Continue PM and inspections

In addition, I is planned to do level 2 inspections in 2020 of: the intake and outfall structure; the pumphouse and outfall sumps; and the pipes to and from the unit and to the outfall.

9.1.4.6 Risk Assessment

The Risks identified in the 2010/11 Condition Assessment and 12017 update report all remain "low", particularly given the March 2021 generation end of life.

9.1.4.7 Life Cycle Curve and Remaining Life

An updated/revised Life Cycle Curve (Figure 9-9 in the 2011 report) is not within the scope of the study.

The Life Cycle identified in the 2010/11 Condition Assessment for the various elements of the Unit 2 Cooling Water Systems Associated with Generators has not changed much. Travelling screens and the CW pumps have been inspected and overhauled. The pumps should have a longer life than shown in 2010/11.

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2030+ timeframe range.

9.1.4.8 Level 2 Inspections – Unit 2 Cooling Water Systems Associated with Generators

No Level 2 inspections are planned in 2020. Video check as practical of intake and discharge piping are suggested in 2021-2023.

9.1.4.9 Capital Projects

No capital enhancements for Unit 2 Cooling Water Systems Associated with Generators are warranted at this time.

9.2 Unit 2 – Lower Priority Systems (2011 Report Identification)

9.2.1 Asset 7786 Unit 2 Boiler System

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 7794 #2 Steam drum, 7789 #2 Downcomers and feeder piping as required 7789 #2 Lower Waterwall headers 7789 #2 Waterwall Tubing 7789 #2 Upper Waterwall headers, and riser piping as required
	7811 #2 Superheater; headers and tubing
	7835 #2 Reheater; headers and tubing
	7789 #2 Safety Valves
	7787 #2 Furnace structural, hangers and casing

9.2.1.1 Description (No change since 2010/11 Report and 2017 update)

9.2.1.2 History

Note: The boiler system has been a major source of unreliability in 2012 to 2017. Hence in 2017 to 2020 it is actually considered a key system, if not the key system. The Boiler Blowdown Tank was replaced in 2011.

9.2.1.3 Inspection and Repair History (No change since 2010/11 Report and 2017 update)

Minor and Major overhauls (last major 2018) alternate. Major Level 2 inspection and repair projects were implemented on Units 1 through 3 in 2012 to 2017 as a result of the previous 2010/11 Condition Assessment and significant tube failures and reliability losses in 2015. This has resulted in sections of the boiler that were experiencing significant wall thickness loss and/or cracking being replaced in 2016. Results of these are documented in several recent reports.

The B&W Engineering Recommendation Unit #2 RH 2012 assessment indicated that RH tube thinning was due to internal corrosion rather than external erosion. It was noted that reheat tubes, particularly horizontal sections are not fully drainable and often show signs of out of service internal corrosion due to oxygen pitting.

> B&W Canada Engineering has reviewed the minimum thickness values and the UT results that were provided, and we have the following recommendations:
>
> - B&W recommends monitoring with regularly schedule UT examination any tube that is between the initially ordered thickness and 85% on the initially ordered thickness
> - B&W would recommend replacement of any tube that is less than 85% of initially ordered thickness or less than the code minimum thickness
> - Secondary reheater tubes 2.125" OD x 0.148" MW SA213 TP304H (Code minimum thickness 0.106") should be replaced where the wall thickness is less than 0.126"
> - Secondary reheater tubes 2.125" OD x 0.203" MW SA213 T9 (Code minimum thickness 0.192") should be replaced where the wall thickness is less than 0.192"
> - Secondary reheater tubes 2.125" OD x 0.148" MW SA213 T22 (Code minimum thickness 0.127") should be replaced where the wall thickness is less than 0.127"
> - B&W recommends replacement of tube sections with outside diameter, wall thickness and materials as close as possible to the original selection. Arbitrarily increasing the thickness or upgrading the material grade may lead to pressure drop/flow balance issue or mechanical problems
> - Refer to B&W PSB-26 for tube thickness evaluation repair or replace guideline
> - B&W recommends the removal of a section of tubing that shows signs of thinning for inspection and analysis to confirm the mechanism

From Alstom's ESO-003817 2014 PSH Tube Failure Analysis Alstom indicated:

> **1. Executive Summary**
>
> Based on the analysis that Alstom has performed, there are no clear indications that the location where the tube failure occurred has any over-stressing from normal boiler operation. Factors such as spreading the assemblies for maintenance over the 40 years of operation as well as the number of start-ups and cool-downs may have caused cyclic fatigue in the attachment. When thermal cyclic fatigue is introduced to the attachment there is a possibility that the stresses in the tube material at the failure location may have been stressed beyond its fatigue limit. This results in a possibility of crack initiation.
>
> The analysis has shown that the steady-state stresses in the failure location are high enough to propagate a crack. If the failed attachment in the Low Temperature Superheater (LTSH) had a pre-existing crack, the cyclic thermal fatigue of the material may have caused the crack to propagate and lead to failure.

The Unit #2 - PSH Tube Failure Summary 2016 SH Tube Attachment and Unit #2 - PSH Tube Failure Summary 2014 SH Tube Attachment assessments indicated that inspections should be done on about 50 similar locations every six years, noting high stress occurring at bottom.

The Unit #1 & #2 Summary of RH Repairs 2016 Emergency Repairs indicated through ultrasonic testing that there were pin holes in Platens 18, 28, and 29 and a total of seven leaks.

In the U2 Lower RH Replacement Summary 2016 assessment:

- Many lower RH tubes were found with thickness less than minimum
- Hot ash corrosion (as opposed to Out of Service corrosion) was most prominent
- Tubing previously purchased and additional orders
- Run until failure – major failures in Jan 2016 led to replacement

In 2017 through 2019, significant sections of the economizer and air preheater also underwent deep cleaning to improve air flow and combustion.

Boiler Tube Sampling on Unit 2 were conducted in 2013 and 2017;

In B&W Boiler 2018 Condition Assessment Report, Team Ultrasound Examination reports on Unit 2 are summarized:

- Unit 2 Supports (failures/cracking) – Status: Completed.

In 2017 significant sections of the economizer and air preheater also underwent deep cleaning to improve air flow and combustion.

In 2011 the boiler blowdown tank was replaced.

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.

Economizer Tubing

The 2011 Level I assessment estimated the risk level as "Low". Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the inspection, assessment and management of tubing condition. Boiler tube thinning leading to tube failures has been identified as a reliability risk in an assessment conducted by NLH. Economizer tube wall thickness measurements indicate the end of life estimate is acceptable. No operational issues have been noted since the original assessment; thus, the estimated risk level remains "Low". No specific maintenance actions are required but standard boiler tubing inspections should continue.

Economizer Headers

The 2011 Level I assessment estimated the risk level as "Medium" and "Low" for the inlet and outlet headers, respectively. Borehole cracking has been observed in Units 1 and 2. (Note: Cross-ligament cracking has been observed in Unit 3 and an issue to monitor going forward for all units.) Recommendations for tighter control of the header temperature have been made to prevent thermal fatigue that can drive the crack growth. FAC has also been observed in the Unit 1 and 2 headers. No operational issues have been noted since the original assessment, but the potential for continued crack growth remains. (The estimated risk level remains "Medium".) There are no specific expenditures planned for the economizer headers, but Boiler Overhauls are planned for each year. Continued inspections have been part of the regular boiler maintenance under the Level II condition assessment follow-up scope. Instrumentation recommendations have also been made.

In the AMEC 2017 Condition Assessment Level 2 Report:

> Two locations on Unit 2 had measurements below the ASME calculated pressure-based minimum wall thickness [8] Piping to the Economizer inlet header and FE 554. A temporary weld buildup was applied to FE554 and replacement was planned for September 2017 [9].
>
> The economizer inlet header piping thinned area was too large to apply a National Board Inspection Code compliant weld repair. Instead this location was dispositioned through analysis. Replacement was planned for September 2017 and analysis using the guidance in EPRI NP-59911-SP [10] and the ASME B31.1 standard was applied to allow operation until replacement [11]. Both locations were placed in the fall 2017 Unit 2 outage.
>
> As part of an effort to disposition the low FAC inspection findings, re-rating of the feedwater piping in the Holyrood units was considered. The FAC inspection results and piping replacements demonstrate that the burden for remediation and analysis will increase with advancing plant age. In particular areas adjacent to welds, where the machined counter-bore contributes to the reduced margin on wall thickness, will necessitate repairs on otherwise acceptable pipe segments. In an attempt to address this concern, an investigation into the necessary steps to reduce the registered design pressure was undertaken [12], however the effort for re-rating was significant and therefore this option was not pursued. It is recognized that the expectation is for an increasing number of piping replacements on the feedwater system in future outages.
>
> Internal video inspection of the Unit 1 and Unit 2 economizer inlet headers was planned but only the Unit 1 inspection could be completed. The inspection report did not note any concerning indications, e.g. extension of the existing thermal fatigue cracking. The report did mention that the colour of the scale appeared to have changed. Images from the inspection video also show small dark spots. These do not appear to be an integrity concern but other changes to the internal scale should be noted in the next scheduled inspection in 3 years.

<u>Linking Piping</u>

The risk level for the economizer link piping was estimated as "Low". No inspections were conducted and no operational issues have been noted since the original assessment. (The estimated risk level remains "Low".) There are no specific expenditures planned. No specific maintenance actions are required. Expected to be suitable for 2023 end of normal service and likely to 2027+ for emergency/stand-by operation.

Furnace Water Circuit

The major components of the furnace water circuit consist of the water walls, headers, feeder tubes, stream drum, downcomers and riser tubes. These components had a 2011 risk level of "Medium", with the exception of the upper waterwall headers, which were "Low". Level II inspections since 2011 found inactive pitting in riser tubes, feeder tubes and waterwall headers, and downcomer penetration cracking. No operational issues have been noted since the original assessment. The estimated risk levels are unchanged.

There are no specific additional expenditures planned for the furnace water circuit, but Boiler Overhauls are planned for each year. Continued steam drum downcomer penetration inspections and other occasional inspections are part of the regular boiler maintenance under the Level II condition assessment follow-up scope.

Superheater Headers

The Front Horizontal Space Outlet Header (SH6) and the Superheater Link Piping were assessed in 2011 as "High" risk. The remainder of the superheat headers and attemperator were assessed as Medium or low. Level 2 Inspection efforts have focused on the SH6 (or Main Steam) headers and outlet nozzles. Inspections found nozzle weld cracks and stub tube cracks in Units 1 and 2. Replication in 2017 did not find indications of high temperature creep to date. No operational issues have been noted since the original assessment. The estimated risk levels are unchanged.

There are no specific expenditures planned for the superheat headers, but Boiler Overhauls are planned for each year. Continued header inspections at regular intervals are part of the boiler maintenance under the Level II condition assessment follow-up scope.

Superheater Tubing

Superheater tubing was assessed as "Low" and "Medium" risk. Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the inspection, assessment and management of tubing condition.

Boiler tube thinning leading to tube failures has been identified as a reliability risk in an assessment conducted by NLH. Superheat tube wall thinning and inner diameter (ID) oxide scale are contributing to a reduced creep life estimate. (NOTE: i.e. Additional tube inspections are being planned on Unit 3 to confirm tube wall thickness and oxide depth – still acceptable for Unit 2).

Reheater Headers

The reheater inlet (cold reheat) and outlet (hot reheat) headers were assessed in 2011 as "Medium" and "Low" risk, respectively. Level 2 Inspection were carried out in 2017 on both headers. No significant findings were noted. Replication did not identify high-temperature creep damage. The estimated risk levels are unchanged. '

There are no specific expenditures planned for the reheater headers, but Boiler Overhauls are planned for each year. Continued header inspections at regular intervals are part of the boiler maintenance under the Level II condition assessment follow-up scope.

Reheater Tubing

Reheater tubing was assessed in 2011 as "Medium" risk. Boiler tubing inspections are part of the regular boiler maintenance on each unit. As a result of failures on Unit 1, repairs/replacements were undertaken to Unit 2. Risk is now considered "Low". Boiler tubing inspections are part of the regular boiler maintenance on each unit. These programs are credited with the general assessment and management of tubing condition.

Safety Relief Valves

As noted in the 2011 Level I assessment, the HTGS boilers Safety Relief Valves (SRVs) are inspected and maintained as per the SRV testing and overhaul program. The program is considered adequate to maintain the SRVs for the desired life.

Furnace Structural Hangers and Casing

The boiler hangers are checked annually. No issues have been identified to date. The annual inspections are considered sufficient to maintain the structural hangers to the desired end of life.

The furnace is pressurized and leaks are repaired promptly to avoid safety concerns in the plant. The casing is generally in good condition. Potential areas of concern that require routine actions are the expansion joints and air-heater seals. Expansion joint repairs are routine maintenance. There was a U2 igniter air duct failure (2017). The end of the duct disengaged from the igniter and the backflow of hot combustion gas out of the boiler ignited nearby cables. This incident is not considered to be a result of ageing degradation and thus is not applicable to the Level I assessment.

To identify possible issues with the boiler casing, infrared (IR) cameras could be used. The station should consider the use of IR cameras can identify leaks at an early stage.

Furnace Combustion Systems

The furnace combustion system includes the burners, fans and air heaters. These components are inspected regularly and maintained by contractors. A recent assessment by Howden Ljungstrom was performed on the air heaters. Air heater upgrades are also being planned, though these expenditures do not appear in the Capital Investment Plan.

The forced draft fans are subject to routine inspection and repair by an external consultant, Fan Dynamics. Reports indicate that U2 fans have had a vibration problem causing damage in the expansion joint. Work has been undertaken to reduce this.

No capital investment is noted, however the routine inspections and repairs recommended by the fan consultant are assumed to address the current and future degradation issues.

High Pressure Piping

Main Steam Piping

The main steam piping was assessed in 2011 as “High” risk. The primary concern was for creep and creep fatigue due to the high operating temperature and pressure. Inspections were executed in 2017 as part of the Level II condition assessment. There were no significant findings, but follow-up inspections to monitor for creep damage were recommended. As a result, the risk would now be “Medium” or lower.

There are no specific expenditures planned for the main steam piping replacements, but Boiler Overhauls and Level 2 Condition Assessments were planned each year to 2021, and should address the entrance the main steam elbow to control valves/turbine casing – GE considered 2021 OK given operating hours, but should reassess. Focused Level 2 Inspections should continue through 2023 desired end of normal operating life and likely continue every three years during the cold standby/emergency period, with Regulatory required either every year or as may be negotiated with the Regulator.

Cold Reheat Piping

The cold reheat piping was assessed as "Low" risk in 2011. Inspections were executed as part of the Level II condition assessment. Minor pitting was noted in Unit 1 but no other findings were noted. There are no specific expenditures planned. No additional follow-up inspections are recommended. CRH drains in good condition. Condensate pots not in service.

Hot Reheat Piping

The hot reheat piping was assessed in 2011 as "Medium" risk. The primary concern was for creep and creep fatigue due to the high operating temperature. Inspections were executed as part of the Level II condition assessment. The findings did not indicate degradation of the piping (Note: Some hanger failures were found in 2014 inspections of Units 1 through 3). What was believed to be a weld defect was also identified and repaired in 2016. Follow-up inspections to monitor for creep damage were recommended and continue to be executed.

The hanger failures highlighted the need for regular hanger monitoring. Proper pipe support is critical for high-energy piping as high stress areas can lead to premature failure. Hanger monitoring is now being executed yearly in both the hot and cold condition for all units.

There are no specific capital expenditures planned for the hot reheat piping, but Boiler Overhauls and Level 2 Condition Assessments were planned each year to 2019. Level 2 Inspections should continue through 2020 desired end of life.

High Pressure Feedwater Piping

The high-pressure feedwater piping was assessed in 2011 as "High" risk. The primary concern was for flow accelerated corrosion (FAC) due to the temperature, process chemistry and pipe material. FAC was a known issue for HTGS and additional inspections were executed as part of the Level II condition assessment. Multiple areas of low wall thickness were noted and the scope was expanded to other at-risk locations in subsequent years. The FAC degradation has led to the pad weld repairs and piping replacements in every unit. The risk is currently assessed to be "Medium Risk" or less, but FAC will continue to be a concern until the end of life.

Boiler Overhauls are planned for each year and Level 2 Condition Assessments to 2019. As the plant ages the scope of repairs and replacements are expected to increase. It is recommended that these Condition Assessments and inspections be continued through to end of life, per the re-inspection times indicated in the previous FAC assessments.

No specific capital expenditure is planned. Depending on the results of detailed Condition Assessments, consideration should be given to the procurement of spare piping components so that replacements can be executed in a timely fashion.

9.2.1.4 Condition Assessment

Boiler and high-pressure piping systems Level 2 inspections, and associated mitigation/repairs (in additional to annual boiler maintenance program) have been ongoing since the 2011 report. Major work has been undertaken in various sections of the boiler such that most of the boiler is currently in reasonably good condition. Nevertheless, one issue that arose in 2017 is the condition of the Boiler Stop Valves (failure and removal on Unit 1 - identified in 2011 as having no recent information on Unit 2 condition, and no recent condition assessment work has been done).

Generally, it is considered that the Unit 2 boiler is in reasonably good condition to reach a March 2023 normal generation life and able to meet end of emergency/standby generation life in March 2027+generation end of life.

9.2.1.5 Actions

Based on the condition assessment and work done on the units since 2011, the following actions are recommended:

- Continue program of detailed Level 2 inspections and tests as per Level 2 Boiler assessments. Including: Superheater Front Horizontal Space Outlet Header; Reheater Outlet Header
- Inspect Unit 2 Boiler Stop Valves and based on results, assess removal/refurbish/replace options

9.2.1.6 Risk Assessment

Since the 2011 issue of the Level I report, all of its “High” risk items have been inspected per the recommended Level II scope. Additionally, several “Medium” and “Low” risk areas were also inspected. Within the scope of this report, there has only been there have only been two significant failure events causing an extended outage – 2017 U2 igniter air duct failure and Unit 1 Boiler Stop Valve failure. In the case of the 2017 U2 igniter air duct failure, the end of the duct disengaged from the igniter and the backflow of hot combustion gas out of the boiler ignited nearby cables. Although not considered a result of ageing degradation this incident does emphasize that a plant can be vulnerable in many areas, requiring the diligence of personnel to identify issues and prevent larger problems.

Boiler overhauls are planned for each year of operation to 2023 and further Condition Assessments to 2019 (recommended to be continued to end of life). As in previous years, the expectation is that recommended follow-up inspections from the Level II assessments will be completed. The two major risks are creep in high temperature components and FAC in the feedwater lines. These are both potentially “High” risk areas. Thermal transformation of the high temperature piping and headers has been observed and repairs and replacements have been performed on the feed water piping. Both these areas will continue to require inspection (and repairs as found).

Other degradation mechanisms require monitoring to ensure that they do not continue to progress (e.g. corrosion in the water circuit), or that any progression of damage does not threaten the component integrity (e.g. economizer inlet headers, downcomer penetrations).

The primary High-Risk Level items are:

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Space Outlet Header	Creep and thermal fatigue	3	D	Low to Med
Reheater Outlet Header	Creep and thermal fatigue	3	D	Low to Med
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med

Others are medium or low risk. A comprehensive list is included in NSS Report

Component	Major Issues	Likelihood	Consequence	Risk Level
Economizer Inlet Headers	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	3	B	Med
Economizer Outlet Headers and Link Piping	Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion.	1	B	Low
Upper WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking in flat end welds. Corrosion	2	B	Low
Riser Tubes	Corrosion, Corrosion Fatigue	3	B	Low
Lower WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	3	B	Low
Feeder Tubes	Corrosion, Corrosion Fatigue	3	B	Low
Downcomers	Thermal/Mechanical Fatigue Cracking at the header support locations	3	B	Low
Steam Drum	Thermal fatigue cracking, Corrosion-fatigue cracking	3	C	Low
Superheater Steam Cooled Walls Outlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Inlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Outlet Header	Creep and thermal fatigue	1	C	Low

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Support Tube Inlet Header	Creep and thermal fatigue	3	C	Med
Superheater Front Horizontal Platen Inlet Header	Creep and thermal fatigue	1	C	Low
Reheater Inlet Header	Thermal fatigue.	1	B	Low
Superheater Link Piping and Attemperator	Thermal/Mechanical Fatigue, Corrosion-Fatigue, Corrosion.	3	C	Med
Economizer Tubes	External corrosion and corrosion-fatigue.	1	B	Low

Piping System	Damaging Mechanism	Likely-hood	Consequence	Risk Level
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med
Hot Reheat	• Thermal/Mechanical Fatigue • Corrosion, • Creep, Creep-Rupture, • Cracking	3	C	Med
Cold Reheat	• Thermal/Mechanical Fatigue, • Corrosion-Fatigue, • Cracking, • Corrosion	1	B	Low

9.2.1.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report and the major Level 2 Inspections and mitigations that have been completed in 2012 to 2017, the primary change to the Life Cycle

Curve would be that the yellowed "Risk Area" will all have shifted to area between 2025 and 2030+ timeframe range.

It is likely legacy impacts will have greater effects on component replacements and refurbishments going forward to 2023. With ongoing inspections and refurbishments, 2023 is achievable with good reliability and 2027 for emergency/standby OPI.

9.2.1.8 Level 2 Inspections – Unit 2 Boiler System

The risk ratings are largely unchanged from the original Level I assessment. This is a result of the advanced age of the station. Continued inspection and maintenance will mitigate these concerns but despite significant mitigating actions completed (replacements/repairs to date, Level 2 Condition Assessments); the risk level has not been greatly altered but also has not increased.

Regular maintenance and follow-up on high risk items will become increasingly important for safe and reliable plant operation. Station programs credited here and other regular inspections must be continued and the findings addressed. Changes to the programs or regular inspections can impact the likelihood of a failure event, if not properly mitigated.

Given the condition historical data reviewed, the required Level 2 analyses, assuming that the current plant inspection and maintenance program is maintained or improved, are those periodic Level 2 as per current 2016 Level 2 program results. In particular Level 2 work should continue on those elements identified in the risk analysis as "high" (and repeated below).

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Space Outlet Header	• Creep and thermal fatigue	3	D	Low to Med
Reheater Outlet Header	• Creep and thermal fatigue	3	D	Low to Med
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	Low to Med
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	Low to Med

Table 4-2 Amec Inspection Recommendations for NLH HTGS Unit 2

Component/Location	Inspection Dates	Inspect for	Methodology
Economizer Inlet Header	2020	Borehole ligament cracks	Visual and PAUT
RH Inlet Header	None before 2022		
RH Outlet Header	None before 2022		
SSH Inlet Header	None before 2022		
SSH Inlet Header	2019	Creep	Visual and Replica
WW Lower Header	None before 2022		
WW Upper Header			
High Pressure Feedwater Header	-		
PSH Outlet Header	-		
Economizer Inlet Header Piping	None before 2022		
Feedwater Piping	2019	Wall thinning / FAC	UT grid
		Heater No. 6 bypass piping	
	2021	Wall thinning / FAC	UT grid
		Heater No. discharge piping	
	None before 2022	All remaining locations	
Link Piping to Attemperator	None before 2022		
Boiler Feed Pump Piping	None before 2022		
Cold Reheat Stem Piping	None before 2022		
Hot Reheat Steam Piping	None before 2022		
Main Steam Piping	None before 2022		
RH Attemperator Refill Piping	-		
SSH Attemperator Piping	-		
Steam Drum	2019	Thermal fatigue cracking	MT
		Steam drum downcorner penetration	

Component/Location	Inspection Dates	Inspect for	Methodology
Supports	2018 & 2020	Failures / cracking	Visual / MT
Economizer Tubes	None before 2022		
Lower Vestibule Feeder Tubes	-		
Lower WW Header Feeder Tubes	None before 2022		
WW Tubes	None before 2022		
PSH Tubes	None before 2022		
SSH Tubes	None before 2022		
RH Tubes	None before 2022		
Riser Tubes	-		

In 2019 B&W Report

Table 4- 2 Inspections on HGTS Unit 2

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
2	Header	SH-6 Header Outlet Nozzle Welds	Creep crack (2015)	2019	Some active cracking observed; cracks were ground out	2020	PAUT, MT, Replica
2	Header	SSH Inlet (SH5) Tube-to-Header Welds		2018	No indications observed	2021	MT, UT
2	Header	SSH Outlet (SH6) Tube-to-Header Welds	Cracks (2018)	2018	Cracks excavated, and weld repaired	2020	MT, UT
2	Header	Superheater Front Horizontal Spaced Outlet Heater SH-6		2016	No cracking at long seam weld	2026	PAUT
2	Header	PH2		2015	Longitudral weld on the south side of the header was found	2025	PAUT

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
2	Pipe	FAC Site 2-1	FAC (2012)	2016	Reinspect in 3.5 years; to be replaced in 2017	2020	UT grid
2	Pipe	FAC Site 2-2	FAC (2012)	2016	Reinspect in 5.0 years; to be replaced in 2017	2021	UT grid
2	Pipe	FAC Site 2-3	FAC (2012)	2019	Pad weld in 2016; no significant wall loss in past 3 years	2022	UT grid
2	Pipe	FAC Site 2-4	FAC (2012)	2016	Reinspect in 7.5 years	2023	UT grid
2	Pipe	FAC Site 2-5	FAC (2012)	2016	Reinspect in 10.4 years	2026	UT grid
2	Pipe	Boiler Stop Valve Inlet Weld		2015	No creep damage observed	2025	Replica, PAUT, MT
2	Pipe	MS West Turbine Terminal		2015	No creep damage observed	2025	Replica, PAUT, MT
2	Steam Drum	Steam Drum Downcorner Nozzle	Thermal fatigue cracks (2012)	2019	Possible minor indications observed	2021	Wet fluorescent MT
2	Tubes	Boiler Floor Tubes	Wall Thinning	2019	Two locations on Hot Side below recommended repair/replace thickness, others approaching this value	2020 (Hot Side) 2025 (Cold Side)	UT
2	Tubes	Waterwall Tubes	Wall thinning / pitting	2019	Some pitting and ID scale destabilization due to upset chemistry event	2025	Metallurgical Assessment
2	Tubes	Lower Vestibule Feeder Tubes		2015	No fatigue cracking	2025	PAUT
2	Tubes	Economizer Tubing	Wall Thinning, Creep	2016	Wall thickness above repair/replace criteria	2025	UT

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
2	Tubes	Primary Superheater Tubing	Wall Thinning, Creep	2016	Wall thickness at some locations fell below repair / replace criteria	2021	UT (NOTIS RLA)
2	Tubes	Secondary Superheater Tubing	Wall Thinning, Creep	2016	Wall thickness at some locations fell below repair/replace criteria	2021	UT (NOTIS RLA)
2	Tubes	Reheater Tubing	Wall Thinning, Creep	2016	Wall thickness at some locations fell below repair/replace criteria	2021	UT (NOTIS RLA)

Boiler Inspections History and Projections to 2021

Ma Major
Mn Minor

Boiler Overhaul Schedule

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Unit #1	Ma	Mn	Ma	*	Ma	Mn	Mn	Ma	Mn	Ma	Ma	Mn			
Unit #2	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma			
Unit #3	Ma	Ma	Mn	Ma	Mn	Ma	Mn	Mn	Ma	Ma	Mn	Ma			

*No Boiler Overhaul for U1 in 2013

9.2.1.9 Capital Projects

Significant improvements have been made in the Boiler Systems in 2011-2019. No specific additional capital enhancements for Unit 2 Boiler System are warranted at this time, other than continued Level 2 inspections and associated mitigation measures.

9.2.2 Asset 7978 – Unit 2 Feed Water System HP Heat Exchangers

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

9.2.2.1 Description (No major change since 2010/11 Report and 2017 update)

9.2.2.2 History (No major change since 2010/11 Report and 2017 update)

9.2.2.3 Inspection and Repair History (No major change since 2010/11 Report and 2017 update)

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. High pressure feedwater discharge piping had Level 2 done and mitigated. No other Level 2 inspections done, but not high priority HP Htr shell checked in 2016.

The original Unit 2 HP feedwater heat exchangers HP-4, HP-5 and HP-6 were replaced in 1988 and HP-5 again in 2009 due to excessive tube failures due to stress corrosion cracking. HP-4 and HP-6 operate at lower temperature and have had less tube failures as a result. They have some risk of more failures as they are significantly older than the average life expectancy of 20 years before the year 2023.

The boiler feed pumps have a spare stage available for reliability purposes. Vibration monitoring was upgraded in 2015. Regular inspections and tests and overhauls of pumps and motors have been maintained

The U2E BF Pump was changed out in July 2014 (last 2004) and the U2 West BF Pump in 2017 (U2 West BF Pump - Service Report May 26, 2017) (last Sept 2010).

9.2.2.4 Condition Assessment

No issues identified. The HP heaters and boiler feed pumps and motors are expected to meet the 2023 end of normal generation life, and likely to the 2027+ cold standby timeframe, with continuing PM and maintenance. . The BFP and motors are tested and inspected regularly. There is a spare pump stage available and a spare BFP motor. The HP Htrs have given no indication of issues and the plant should be able to address single failure issue in short term. The High-Pressure feedwater discharge piping had Level 2 done and mitigated.

9.2.2.5 Actions

Based on the Condition Assessment, no Actions beyond ongoing inspections and PM are recommended.

9.2.2.6 Risk Assessment

Both from a technological perspective and a safety perspective, the Risk Assessment associated with the HP Heaters and Boiler Feed Pump/Motors is low. The BFP and motors have been tested and inspected regularly and there is a spare pump stage and spare motor available. The HP Htrs have given no indication of issues and the plant should be able to address single failure issue in short term.

Component	Tag Name	Major Issues	Likelihood	Consequence	Risk Level
Unit #2 HP Feedwater Heater #4	HP-4	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	3	B	Medium
Unit #2 HP Feedwater Heater #5	HP-5	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	1	B	Low
Unit #2 HP Feedwater Heater #6	HP-6	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	3	B	Medium
All HP Feedwater Heaters		SCC, Thermal/ Mechanical Fatigue	1	C	Low

9.2.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" will all have shifted towards the 2020 to 2030 timeframe range.

The curves indicate that the remaining life (RL) of the Unit 2 HP Heat Exchangers (and the associated feedwater systems) are very likely able to reach the desired life (DL)

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 would be illustrated by this curve and very likely able to reach desired end date of March 2023 for normal generation and 2027+ for cold standby/emergency generation.

9.2.2.8 Level 2 Inspections – Unit 2 Feed Water System HP Heat Exchangers

Given the condition assessment and historical data, no further Level 2 analyses are required, premised on the current inspection and maintenance program for the system is maintained or improved.

9.2.2.9 Capital Projects

No additional capital enhancements for the systems are recommended, provided the spare motor remains available and vibration monitoring is being monitored. Variable speed drive replacements are not warranted.

9.2.3 Asset 8017 – Unit 2 Feedwater System - Deaerator

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 (No major change since 2010/11 Report and 2017 update)

9.2.3.2 History (No major change since 2010/11 Report and 2017 update)

9.2.3.3 Inspection and Repair History (No major change since 2010/11 Report and 2017 update)

A Level 2 inspection was performed on deaerator storage with no major findings/actions. From the 2017 B&W 2017 Sep 15 B&W report, the internals were removed to access and visually inspect components and nozzles. Team carried out magnetic particle examinations of longitudinal, circumferential, shell attachment and nozzle penetration welds. Four areas identified were repaired (non-pressure boundary areas).

9.2.3.4 Condition Assessment (No major change since 2010/11 Report and 2017 update)

The deaerator and deaerator storage tanks were assessed in 2011 as "Medium" and "Low" risk in the Level I report. The storage tanks are inspected every year as part of regular maintenance. Local repairs are regularly performed but there have been no significant issues noted. The 2017 Level 2 inspection on the deaerator required no further actions after the repairs were made for Unit 2 in 2017.

No issues/changes in the 2011 Report on the condition assessment of the Unit 1 feedwater system - deaerator was identified. The Unit 2 deaerator and storage tank are considered in good condition and able to achieve generation end of life in March 2021.

9.2.3.5 Actions

No new high priority actions were identified. Maintain regular PM's/inspections.

9.2.3.6 Risk Assessment

The risk assessment associated with the Unit 2 feedwater system - deaerator, from a technological perspective and a safety perspective, is illustrated below. None are a high level or life limiting risk.

Component	Major Issues	Likelihood	Consequence	Risk Level
Deaerators	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	3	B	Medium
Deaerator Storage Tanks	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	2	B	Low
Deaerators/ Storage Tanks	Corrosion-Fatigue and Thermal Fatigue,	1	D	Medium

9.2.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" will have shifted towards the 2025+ timeframe range. '

The curve would indicate that the remaining life (RL) of the Unit 2 Feedwater System - Deaerator exceeds the desired life (DL) which is end date for generation of March 2023.

9.2.3.8 Level 2 Inspections – Unit 2 Feedwater System - Deaerator

Given the condition historical data reviewed, no additional Level 2 analyses are required. A Level 2 inspection of the deaerator with internals removed planned for 2020 to check for flow accelerated corrosion should be assessed.

9.2.3.9 Capital Projects

No additional capital enhancements for the Unit 2 feedwater system –deaerator are suggested.

9.2.4 Asset 7992 – Unit 2 Feedwater System - Low Pressure Feedwater Heat Exchangers

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

9.2.4.1 Description (No major change since 2010/11 Report and 2017 update)

9.2.4.2 History (No major change since 2010/11 Report and 2017 update)

9.2.4.3 Inspection and Repair History (No major change since 2010/11 Report and 2017 update)

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 discussions with plant operations staff, it was noted that there were no performance issues associated with the LP feedwater heat exchangers servicing Unit 2.

The south extraction pump and motor was overhauled in 2014 and the north extraction pump and motor was overhauled in 2016. A spare condensate extraction motor was procured and available. No Level 2's performed, but spot checks on some tanks.

9.2.4.4 Condition Assessment

The Unit 2 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered in good condition and able to achieve end of normal generation life of March 2023 and able to meet end of emergency/standby generation life in March 2027+.

9.2.4.5 Actions

Based on the Condition Assessment, no Actions are recommended for the Unit 2 Feedwater System - Low Pressure Feedwater Heat Exchangers. Maintain regular PM's/inspections.

9.2.4.6 Risk Assessment

There has been no significant change in the Risk Assessment associated with the system from 2010/11 C.A and 2017 update report, both from a technological perspective and a safety perspective. There are no high priority issues. The Unit 2 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered low risk, able to achieve end of normal generation life of March 2023 and able to meet end of emergency/standby generation life in March 2027+.

9.2.4.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will likely have shifted towards the 2025 to 2030 timeframe range.

The Feed Water System LP Heat Exchangers will likely be able to reach the desired life (DL) March 2021 end date for generation. Although no detailed NDE information has been obtained on the LP heat exchangers, a detailed Level 2 inspection is likely not warranted at this time given the normal generation life of 2023 and able to meet end of emergency/standby generation life in March 2027+.

9.2.4.8 Level 2 Inspections – Unit 1 Feedwater System - Low Pressure Feedwater Heat Exchangers

Given the condition historical data reviewed, No Level 2's inspections are required, provided ongoing inspection and maintenance program and PM's continue.

9.2.4.9 Capital Projects

No additional capital enhancements for the system are suggested.

9.2.5 Asset 7664 – Unit 2 Condenser

Unit #:	**2**
Asset Class #	BU 1296 - Assets Generations

SCI & System:	7638 - #2 Turbine & Generator
Sub-Systems:	7664 # 2 Turbine & Condenser
Components:	271326 #2 Condenser

9.2.5.1 Description (No major change since 2010/11 Reports and 2017 update)

9.2.5.2 History (No major change since 2010/11 Reports and 2017 update)

9.2.5.3 Inspection and Repair History (No major change since 2010/11 Reports and 2017 update)

The Unit 2 condensers are in good shape for their 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.

The condenser steel piping at the inlet and outlet between the condensers and the underground concrete pipes has been replaced.

9.2.5.4 Condition Assessment

The condenser and auxiliaries appear in good condition. There had been an indication that refurbishment or replacement of the vacuum pumps and motors might be warranted. Given the required end data, update this is not likely an issue that cannot be addressed through ongoing PM processes. There is a plan to overhaul the south vacuum pump and motor was overhauled in 2018.

No additional information on Shell, Hotwell or Waterboxes were identified after the 2008 inspection reports that confirmed that all were in good condition. There appears to be some concern on the thickness/corrosion of the steel waterbox shell. No additional information was identified. A Level 2 inspection of the condenser waterboxes is planned for 2020.

9.2.5.5 Actions

Based on the condition assessment, no further actions are recommended for the condenser beyond:

- Continue PM’s, including vacuum pump and motor checks.
- Undertake a condenser waterbox material thicknesses check (repair if/as required).
- Overhaul vacuum pumps and motors, when convenient if warranted.

9.2.5.6 Risk Assessment

The risk assessment associated with the Unit 2 condenser and auxiliaries in 2010/11 C.A and 2017 update had no high risks. Little has changed and no new high risks were identified.

9.2.5.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" for the Vacuum Pump would have shifted to 2020-2023.

The curves indicate that the remaining life (RL) of the Unit 1 Condenser can reach the desired life (DL) March 2021 end date for generation. The exception to this might be condenser waterboxes and the vacuum pumps/motors (a relatively minor issue that can be readily addressed if/as it occurs).

9.2.5.8 Level 2 Inspections – Unit 1 Condenser

Given the condition historical data reviewed, a Level 2 analyses of the thickness measurement/inspection of the condenser waterbox walls is considered warranted.

9.2.5.9 Capital Projects

The suggested typical capital enhancements for the Unit 1 condenser are:

- No new capital subject to waterbox thickness checks (if required likely $750k$ all units).
- Vacuum pump/motor replacements as PM's warrant.

9.2.6 Asset 8878 – Unit 2 FD Fans System (Chapter 9.2.6 in 2011 Report)

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 Blr Heavy Oil System
	7935 #2 Boiler Light Oil
Components:	88781#1 Boiler FD Fan System 7843 # 2 Boiler FD Fan East 7844 # 2 Boiler FD Fan West 7855 # 2 Boiler Steam Air Heater East 7856 # 2 Boiler Steam Air Heater West 7883 # 2 Boiler Main Air Heater East 7884 # 2 Boiler Main Air Heater West
	7916 #2 Boiler Heavy Oil Pump East 7917 #2 Boiler Heavy Oil Pump West 7920 #2 Boiler Heavy Oil Pump steam, valves and pipe 7933 #2 Boiler Heavy Oil Firing 8980 #2 Boiler Light Oil Pump East 8981 #2 Boiler Light Oil Pump West
	7882 #2 Boiler Air Supply Seal Air 7885 #2 Boiler Scanner Air System

9.2.6.1 Description (No major change since 2010/11 Reports and 2017 update)

9.2.6.2 History (No major change since 2010/11 Reports and 2017 update)

Variable Speed/Frequency Drives to the FD fan motors were added in 2015 to provide incremental combustion control and a spare FD fan motor purchased (common to Units 1 and 2). Major in-depth air preheater and economizer cleaning were undertaken in 2017 to reduce generation derating due to air system issues. Poor quality oil (high silica, alumina, susceptible to separation) was utilized in 2015. It caused significant damage to fuel handling systems (heaters, filters, burner tips, pumps) as well as tank deposition requiring cleaning. The fuel specification was subsequently modified, and the fuel improved. It resulted in a major expenditure in 2016 on fuel storage and handling system as a result of damages incurred using poor quality fuel under a new fuel supply contract.

9.2.6.3 Inspection and Repair History (No major change since 2010/11 Reports and 2017 update)

The equipment is checked annually as part of the boiler inspection program. Both the east FD fan motor in 2014 and west FD fans motors in 2015 were overhauled. Variable Speed Drives to the FD fan motors were added in 2015. A spare 4 kV motor was purchased in 2013.

The VFD's are used with the vanes open. VFD's have experienced some cell failures when started up after outages. The power cells overload at 85%. Several of sensors/relays high temp causes trips and alarms due to blocked filter (every 1-2 weeks) in VFD cells.

Poor quality oil (high silica, alumina, susceptible to separation) was utilized in 2015. It caused significant damage to fuel handling systems (heaters, filters, burner tips, pumps) as well as tank deposition requiring cleaning. The fuel specification was subsequently modified, and the fuel improved.

Annual boiler inspections/overhauls (alternating minor and major) and repairs ongoing with OEM.

Major Level 2 inspections and repairs in 2014 to 2017, including significant surface replacements experiencing tube thinning and tube failures.

The Ljungstrum air preheater were refurbished in 2017, and deep cleaned (high pressure wash of HE baskets – while removing a substantial amount of accumulated ash; still considered to overall have had minimal success). Further cleaning and some equipment replacement in 2019 have enhanced performance.

From HTGS 2017 Unit # 2 FD Fan NDE Reports Sep 8, 2017, 100% MT was done on all accessible pipe braces, support bars, split rings, dorsal fins, both blade sides, circumferential welds and balance plates inside fan wheel. No relevant indications were found,

From A022384 - Field Service Report - Babcock Wilcox JL Hydro Holy Rood Station – J Richmond Jul 7, 2015, the airpreheater inspection results were:

- Hot and cold radial seals were in good condition

- Hot end Circumferential seals – West was good; East was poor with severe wear (holding bar improper install; seal tabs severely corroded or missing)
- Cold end Circumferential seals – East was fair; West was good
- End Post seals – West hot seal poor; other hot and cold good
- Baskets appear good condition

From the B&W report in 2016 (A028042 - Field Service REPORT - Babcock Wilcox JL Hydro Holy Rood Station - CIRVING - 8-12-16 Unit 2 Repairs)

- Issues with East drive assembly coupling and keyway and top guide bearing housing repaired or replaced
- East cold and west end sootblower lance nozzles in poor condition – repaired
- West top guide bearing trunnion locking cap bolts sheared off. Damage to sealing tube and metal debris in bearing housing – repaired
- East and west hot and cold end baskets replaced in last four years and in good condition

Conclusions / Recommendations / Summary:

- Align the air side circumferential sealing ring on both APH's HE and CE ends.
- Re-establish the CE circumferential sealing ring at the OB sections of the sector plates/housing.
- Replace all of the post, radial and circumferential seals during the next scheduled outage.
- Replace the CE gas to air sector plates on both APH's.
- Replace the West APH guide bearing, trunnion shaft and bearing trunnion assembly and shaft seal.
- Seal off the excessive gaps between the baskets and baskets and stay plates/diaphragms.
- Clean and replace the steam coils as necessary.
- Replace the West APH top guide bearing and trunnion shaft and bearing assembly sleeve and locking cap and associated hardware.
- Repair or replace the HE trunnion positive air shaft seal on both APH's
- Repair/clean the steam coils

From B&W 2017 inspection report A031090-02 - FIELD SERVICE REPORT -B W JL Hydro Holy Rood - RPARSLEY-9-2017 Unit 2 APH:

- East and west are in fair to good condition
- Replaced cold end sector plate liners, hot and cold ends sector plate liners, hot and cold radial and circumferential and post seals

From B&W report A031090-03 - Field Service advisory - BW - NL Hydro Holyrood Station - Goetschius - 12-2-17 Unit 1 High Press Drop, Howden consulted on issues with high gas and air side airpreheater pressure drop on Units 1 and 2:

- Design gas side pressure drop – 5.1" H2O; current 8.4' H2O
- Design air side pressure drop – 3.4" H2O; current 6.43" H2O
- Steam sootblowers – design 145 psig 200oF superheat; actual: 160 psig, 70oF superheat
- MgO additive discontinued in 2014

- Initial hot water wash water cleaning had minimal effect; high pressure 2500 psig worked for 90% of tubes
- Low S and a low viscosity, indicate a less typical #6 oil – should result in less acid condensed enhanced fouling or poor atomization fouling blockage
- Vanadium of 200 ppm appears significant and may warrant MgO additive – produces molten salt (Van/Sodium) corrosion of metallic type in upper furnace that finds its way into airpreheater over the long term (hence deposits are somewhat magnetic in nature)

B&W did not recommend increasing the low superheat temp of the sootblowing steam, while acknowledging that it would be a factor in the buildup of deposits - largely because the lower level seemed to work for years. B&W quoted for replacing hot end baskets.

Asset 7809 Boilers Flue Gas System, Sootblowers:

The Unit 2 back end flue gas ductwork is original and was installed in 1970. During yearly plant outages, the accessible ductwork has been inspected by boiler contractor. 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 that 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 loading impacts has been significantly reduced.

Asset 7912 Fuel Oil Firing (Valve Trim – Atlantic Controls)

Major parts of the fuel oil filters and heaters were replaced/refurbished in 2015 as a result of the purchase and use of a higher silica/alumina/vanadium oil that year. Fuel changes and the new equipment have improved the situation. Recent reports regarding the condition of the light and heavy oil systems were not available or reviewed. However, the systems had visually appeared to be in reasonable condition. 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. For faster starts, a suggestion that temperature in standby maintain 50 °C versus current temperature switch at 85-90 °C (more consistent with 0.7% sulphur oil vs 2.5% sulphur oil historical basis). For low flow, the main fuel oil control valve is oversize and could use a low flow control valve circuit.

In 2019 significant deposition was noted in unit fuel filters and heaters. The material was very difficult to clean, and a Quebec company's proprietary process was applied to clean out heater tubes. It appears that fuel oil separation and deposition has occurred resulting in a gooey solid coming from both the main and day tanks. (Note that the main tank suction heaters have been covered especially top surfaces with a very hard coating that is no doubt reducing their thermal effectiveness.

9.2.6.4 Condition Assessment

Given the history and operating pattern, the condition assessment of the Unit 2 FD fans and system would suggest:

- Involvement of these systems in the annual boiler inspection is critical.

- The FD Fan is in reasonable shape.
- The FD fan motors are at risk given their age and the impact of VFD operation.
  - A spare motor has been and will likely continue to be a critical spare asset.

Some of the work in the 2011 to 2019 period which helped with Condition Assessment were:

- Air preheater and economizer deep cleaning which significantly helped reduce current air system output derate;
- Boiler hangers were reset to address load issues.
- The oil system which had issues in 2015 requiring major refurbishment have been resolved through an improved oil specification/procurement and system refurbishments/replacements.
- Although another but different problem appears to have arisen in 2019.

The sootblowing system is somewhat limited and it could be improved in terms of coverage and efficiency. More frequent use of APH sootblowing also appears warranted (continuous versus once per day or per shift). No significant capital investment is foreseen.

The Unit 2 FD Fans (& System) are considered in good condition to meet March 2021 generation end of life, provided combustion air issues remain resolved. That could change if unusual operating requirements should result in performance deterioration (cycling, two-shifting, excessive low or high load operation, fuel system clogging).

9.2.6.5 Actions

The primary high priority actions recommended for the Unit 2 FD Fans (and System) is to

- Further assess the VFD operation/optimize air system to maintain unit capacity
- Continue monitoring delta air press to time additional APH/Econ cleaning
- More use of APH sootblowing
- Inspection of FD fans and APH's internally in 2020
- Assess fuel plugging issues for solution for near and longer term
  - For faster starts, assess temperature in standby maintain 50 oC versus current temperature switch at 85-90 oC (more consistent with 0.7% sulphur oil vs 2.5% sulphur oil historical basis).
  - For low flow, assess use of a low flow control valve circuit.

No other high priority items remain from 2011 or since that time, provided annual boiler work and PM's are continued.

9.2.6.6 Risk Assessment

No high risk issues from the 2010/11 C.A and 2017 update report associated with the Unit 2 FD Fans (and System), both from a technological perspective and a safety perspective, remain.

Further maintenance and investigation associated with the air system is considered appropriate for:

- APH and economizer pluggage
- VFD operation optimization
- FD fan motor age (currently managed through spare motor availability)

- Fuel pluggage

9.2.6.7 Life Cycle Curve and Remaining Life

An updated/revised Life Cycle Curve (Figure 9-19 in the 2011 report) is not within the scope of the study.

Given the experience since the 2010/11 Condition Assessment report, the primary changes to the Life Cycle Curve are:

- The plant has procured spare FD motor
- An additional yellowed "Risk Box" for the combustion system and VFD in current timeframe addressing the Unit issues with air system optimization and pluggages (APH, economizer, fuel system)

Given the availability of the spare FD motor, the Unit 2 FD Fans (& System) is expected to meet or exceed the desired life (DL) March 2021 end date for generation. The age of the large 4 kV motors makes continued testing/monitoring programs desirable to effectively monitoring their status.

9.2.6.8 Level 2 Inspections – Unit 2 FD Fans (& System)

Given the condition historical data reviewed, no Level 2 analyses are considered required. Level 2 inspections of the FD fans and airpreheaters were planned for 2020 as part of larger Level 2 project. Continued inspections associated are considered warranted (fuel system plugging; APH and FD fan inspections; APH cleaning).

9.2.6.1 Capital Projects

Given previous air duct refurbs, spare FD fan motor procurements and VFD's, no additional capital projects are recommended beyond current plans.

9.2.7 Asset 7900 – Unit 2 Stack and Breaching

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 271327 #2 Stack Breeching

9.2.7.1 Description (No major change since 2010/11 Report and 2017 update)

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 (No major change since 2010/11 Report and 2017 update)

Stack repairs (liners, breeching) were completed in 2012

9.2.7.3 Inspection and Repair History (No major change since 2010/11 and 2017 update reports)

In 2014 an internal and external Remote Access Technology (Aug 2014 RAT Inspection Assessment) was carried out on Stack #2. The 1/4/2016 B&W/ICM Assessment of 2014 report indicated:

Observations

During ICM's review of the inspection report provided to us, the following issues were observed with the chimney:

- Approximately 12 cracks (vertical and horizontal) and 7 small spalls were visible on the concrete column exterior.
- The external paint is in poor condition for the full height of the chimney.
- There are three bent rungs, one loose rung, one missing stand-off and a warped section of the access ladder.
- The ladder has two different safety rail types in the top and bottom halves.
- The north down lead cable is broken at the base of the chimney.
- There is surface corrosion on some of the rigid conduit. Also, some of the junction boxes are damaged. Finally, the sheath on the flexible conduit is damaged in areas, and incorrect fasteners are used.
- The handrails on the southwest and east sides of the lower platform are loose. Also, there is a broken guardrail on the north side of the top platform.
- The 160' platform level davit arm and which system have surface corrosion on their components.
- The aviation light fixtures on the east and west sides of the lower platform are missing some of their fastening hardware.
- Areas of minor cracks, small spalls, open construction joints and moisture seepage were observed throughout the entire visible column interior.
- The carbon steel liner immediately below the stainless transition was found to be corroded.
- Missing and defective refractory bricks were observed in the breaching interior at the chimney entry.

Recommendations

After a review and study of the information obtained during the inspection, we recommend that the following repairs be carried out on the chimney at the earliest possible convenience:

- Grind out and fully expose all cracks, spalls and failed repairs throughout the exterior concrete shell and seal/repair.
- Thoroughly wash down and prepare the entire surface of the chimney exterior and apply two coats of quality protective paint.
- Repair broken down lead on north side of chimney base.
- Secure loose handrail sections on both platforms.
- Install a stand-off on the access ladder 314' above the ground.

- Replace safety rail above lower platform to match the safety rail system used in the bottom half.
- Replace missing refractory bricks in the breaching inlets.

External Inspection

The report photographs show approximately five small vertical and horizontal cracks on the north and west faces of the stack at various elevations. None of the cracks are large enough or long enough to indicate major structural concerns.

The report photographs also showed ten small concrete spalls where the concrete was either loose or missing. One spall, located at elevation 272' on the north side, was 1' by 1 ½' in size. All the remaining spalls were less than 1 square foot in size. Unfortunately, there is no indication in the report of whether hammer testing was done to assess the extent of spalled or hollow concrete that is not visible yet.

All of the cracks and spalls shown in the report should be replaced and sealed. However, if the defects shown in the report represent the full extent of deteriorated concrete on the stack then the concrete column is in good overall condition. However, the Boroscope videos show evidence of moisture stains on the interior on the concrete in several locations which would tend to indicate there are additional cracks or openings in the concrete not shown in the report or that the paint is sufficiently deteriorated that moisture is penetrating the concrete.

Chimney Paint

The external protective coating was found to be aged, faded and thin throughout the full chimney exterior. In some areas, the paint is extremely deteriorated and/or missing. The paint acts as a protection barrier to the concrete column which extends the life of the column. This is especially important due to the location of this facility. Salt water as well as extremes in weather can attack all components of a chimney. The presence of moisture stains on the concrete column interior shown in the Boroscope videos would tend to indicate that the coating has failed in these areas and moisture is penetrating through the column. Over time this moisture will cause the concrete to deteriorate both through erosion and through expansion and contraction in the winter and spring.

Observations

During ICM's review of the inspection report provided to us, the following issued were observed with the chimney:

- Approximately 5 cracks (vertical and horizontal) and 10 small spalls were visible on the concrete column exterior.
- The external paint is in poor condition for the full height of the chimney.
- The ladder side-rails are discontinuous at the 10' elevation; the ladder is warped at various locations; the rungs 64' and 190' above the ground are loose; the stand-off anchor bolts are not flush with the surface 70', 116' and 180' above the ground and there is a missing connection bolt 208' above the ground.
- The ladder has two different safety rail types in the top and bottom halves.
- There is a damaged sheath on the grounding cable 315' above the ground, west side and there is a broken-down lead anchor 296' above the ground, north side.
- There is surface corrosion on some of the rigid conduit. Also, some of the junction boxes are damaged. Finally, the flexible conduit has incorrect fasteners.
- Two sections of handrail on each platform are loose.

- The 160’ platform level davit arm and winch system have minor to severe surface corrosion on their components.
- The aviation light fixtures on the east and west sides of the lower platform are missing some of their fastening hardware.
- Areas of open construction joints and moisture seepage were observed throughout the entire visible column interior.
- Missing and defective refractory bricks were observed in the breaching interior at the chimney entry.

Recommendations

After a review and study of the information obtained during the inspection were recommended that the following repairs be carried out on the chimney at the earliest possible convenience:

- Grind out and fully expose all cracks, open construction joints, spalls and failed repairs throughout the exterior concrete shell and seal/repair.
- Thoroughly wash down and prepare the entire surface of the chimney exterior and apply two coats of quality protective paint.
- Replace broken down lead anchor and repair damaged grounding cable sheath 315’ above the ground, west side.
- Secure loose handrail sections on upper and lower platforms.
- Replace missing hardware sections on upper and lower platforms
- Replace missing ladder connection bolt 208’ above the ground.
- Replace safety rail above lower platform to match the safety rail system used in the bottom half.
- Replace missing refractory bricks in the breaching inlets.

Repairs

After the inspection was completed, the following repairs were done:

- Four concrete spalls in the interior concrete were repaired.
    - A 1’ wide by 6’ high spall 30’ above the ground on the south side.
    - A 1’ wide by 1’ high spall 52’ above the ground on the south side.
    - A 5’ side by 6’ high spall 278’ above the ground on the west side.
    - A 3’ wide by 1’ high spall 255’ above the ground on the north side.
- Several defective rungs and connection bolts on the external access ladder were repaired.
- Missing clip anchors on the lightning protection system down-lead were replaced
- Missing conduit clips were replaced.
- The loose platform handrails were repaired.
- The aircraft warning lights were repaired.

Observations

During the review of the inspection notes and photographs, the following issues were observed with the chimney:

- The external paint is in poor condition for the full height of the chimney.
- The ladder has two different safety rail types in the top and bottom halves.

Recommendations

After a review and study of the information obtained during the inspection, we recommend that the following repairs be carried out on the chimney at the earliest possible convenience:

- Thoroughly wash down and prepare the entire surface of the chimney exterior and apply two coats of quality protective paint.
- Replace safety rail above lower platform to match the safety rail system used in the bottom half.
- Continue to inspect the stack at regular intervals.

Hatch on Nov 26, 2018 reported:

On the morning of November 15, 2018, NL Hydro noticed what appeared to be an unusual amount of sway in the exhaust stack due to winds gusting over 100 km/hr. During the same period, it was observed that the two adjacent stacks were hardly moving.

Based on the observations from the ground, there appeared to be no cracking or displacement at any of the circumferential construction joints, no new vertical cracks formed on the exterior or significant patches of missing or spalled concrete. The stack movement appeared to start approximetelty one quarter to one third up from the base. The majority of the movement was perpendicular to the direction of the wind and had a constant period. The sway appeared to be a simple single order fixed cantilever movement similar to a musical metronome.

A meeting was held with senior NL Hydro operatons staff regarding safety and operation of the plant. Hatch agreed that althought the stack was swaying there were no obvious signs showing on the exterior that would incicate the stack woulf fail catastrophically. It was decided to continue to closely monitor the stack for any visible signs of concrete failure, new cracks, exposed rebar or spalled concrete, and any increase in the stack movement.

The following observations were made November 16, 2018.

1. No obvious new cracks or displaced concrete at any of the joints, that could be seen from the two vantage points, were visible.
2. There were no evidence of significant concrete missing from the surface or large pieces on concrete
3. There was no obvious displacement of the vertical ladders, platforms or electrical cables.
4. The interior access at ground level required confined entry. Observations were made from the doorway and there was no evidence of fallen concrete or issues with the liner foundation. We understand Hydro personnel entered this area and walked around the liner and inside diamater of the stack and found no evidence of distress i.e. cracks or fallen concrete. Pitcures were taken from the ground of the concrete stack to base slab and looking vertically upwardxc from the base slab. One area has an interior profile that is non corcular in apperarance similar to an inward bulge. This same area on the

exterior does not appear to be bulged and there are no visible signs of cracking or concrete failure.

5. Hydro personnel climb the ladder to access the first platform leve. Three small pieces of concrete were found on the grating. In looking at these pieces they do not appear to be from new cracks. One had a flat face from a concrete saw blade and another contained caulking which likely came from one of the circumferential joints.

9.2.7.4 Inspection and Repair History

The station has as part of its PM program and due to regulatory issues, been diligent in its inspections of the stack from a structural perspective and in making the suggested repairs. Overall the conditions of all the stack, the breeching and ladders and joints are good. No major cracking or structural issues seem to have arisen. The condition of the current linings and cap seem to suggest that the unit has not been operating below the dew point, due to the unit seldom running at full load or below 50% MCR. Also, the annual number of starts and stops is quite low.

The last inspections were in 2017 and 2018. Stack inspections in 2017 and 2018 indicated that some recoating might be warranted, but generally that the concrete stacks are in reasonably good condition and are expected to be able to make the then March 2021 generation end date.

In B&W/ICM Report – April 2018, repair scopes of work for a quote for the #1 and #2 stacks were based on the review of the inspection reports that were provided . The repair scope of work for the #3 stack is based on the stack inspection completed by ICM in 2015.Subsequent to completing the review of the inspection reportsit5 was advised that the stacks would only remain in operation for another five years at most. Based on this information, the repair scope of work originally quoted for the #1 and #2 stacks was reduced to immediately necessary repairs to the concrete column and stack accessories. The painting the stacks or altering the ladder safety rail, nor the work on the breaching brick were included.

When then advised that the stacks could possibly continue in operation to as late as 2023 and would likely be left standing for many years beyond that date, revised quotes that included applying a new coating to the exterior of each of the stacks to help protect the concrete from moisture penetration were added. The scope of work for each of the stacks quoted below includes these revisions.

#2 Stack Repair – Scope of Work

- Grind out and fully expose all cracks, open construction joints, spalls and failed repairs throughout the exterior concrete shell and seal / repair.
- Thoroughly high pressure (min 7000 psi) wash down and prepare the entire surface of the of the chimney exterior and apply a sealer coat to all exposed concrete and apply two coats of quality protective paint specifically designed for coastal environments.
- Replace broken down lead anchor and repair damaged grounding cable sheath 315′ above the ground, west side.
- Secure loose handrail sections on upper and lower platforms.
- Replace missing hardware on lower level aviation lights.
- Replace missing ladder connection bolt 208′ above the ground.

Price

The total lump sum price to carry out all of the repair work on both the #1 and #2 stacks as described above is Four Hundred and Eighty-Five Thousand Four Hundred Dollars ($485,400.00) GST / HST extra.

> NOTE: This price assumes that work on all 3 stacks can be done consecutively so only need to mobilize and demobilize once.

<u>Price Breakdown</u>

The price quoted above breaks down as follows:

> Mobilization / Demobilization = $22,400
> Chimney #1 Repairs = $148,200
> Chimney #2 Repairs = $144,200
> Chimney #3 Repairs = $170,600
> Total = $485,400

9.2.7.5 Condition Assessment

The stack is inspected every three years. Stack repairs to the liners and breeching were completed after 2011 and considered in reasonably good condition. The 2017 and 2018 inspection and repair work indicated that most repairs had been completed, but recommended that the stack be coated, but this has been deferred. The stack and system are expected to be able to make the March 2023 normal mode generation end date and the cold standby/emergency generation mode in 2027+, but the stack should be re-coated.

9.2.7.6 Actions

Based on the condition assessment in 2017, the following actions are recommended:

- Continue stack inspections in 2020
- Consider undertaking coating in 2020/21 period, if future stack inspections verify requirement or if generation extension possible
- Monitor movement of three stacks, especially #2 during windy/gusty days (.75 km/hr parallel with stack alignment) and cordon off area around stacks

9.2.7.7 Risk Assessment

The high risk associated with breeching in the 2010/11 C.A and 2017 update report was addressed. Subsequent inspections and repairs have been completed such that no other high risks were identified as current, except re-coating. Consideration of the stack coating recommended in the 2017 and 2018 if verified in a future inspection should be completed, likely in 2020/21 period.

9.2.7.8 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change is that the Existing Breech risk area would disappear, and the others would not likely change. Stack painting/coating might be added for 2021.

The Unit 2 Stack is considered able to reach the desired life (DL) of March 2023 end date for generation, and likely well beyond, provided current inspections and maintenance are maintained, particularly stack painting/coating.

9.2.7.9 Level 2 Inspections – Unit 2 Stack and Breaching

No additional Level 2 analyses are considered to be required, provided the current plant inspection and maintenance program is maintained or improved. Continue stack inspections and monitor degradation of stacks and liners. Undertake stack re-coating if/when justified in future inspection reports, likely in 2021 to 2023.

9.2.7.10 Capital Projects

No additional capital work is recommended, except stack re-coating is recommended in 2021-2023 period.

9.2.8 Asset 8152 – Unit 2 Electrical and Control Systems (including DCS) Associated with Steam Systems

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 8139 #2 Burner Management 309898 #2, Boiler Protection & Control

9.2.8.1 Description No major change since 2010/11 and 2017 Update Reports)

9.2.8.2 History (No major change since 2010/11 and 2017 Update Reports)

9.2.8.3 Inspection and Repair History (No major change since 2010/11 and 2017 Update Reports)

9.2.8.4 Condition Assessment

The condition assessment of the systems is largely the same as in 2010/11 condition assessment and 2017 update reports, but there have been no recent issues causing outages:

- Foxboro would normally be considered to approach obsolescence in 2021
- Switchgear and Turbovisory remain key issues. Additional spares have been procured.
- Addition Mark V parts have been added and training completed
- OEM supplementary support agreements have been in place for turbovisory.

- No recent issues causing outages.

9.2.8.5 Actions

Based on the Condition Assessment, the following Actions are recommended:

- Maintain existing systems – supplementing spares, securing maintenance agreements with OEM's on Mark V governor and turbovisory and switchgear. Replace as required.
- Continue inspections/testing.

The need for additional actions should be investigated/re-examined about every five years, especially if the normal mode of plant operation should be modified to extend beyond March 2023. Obsolescence and an inability to obtain parts may necessitate some replacements or refurbishments, less likely an overall cost benefit assessment due to reduction due to reduced maintenance costs on newer equipment. Generally, one synch condenser operation would indicate that stage 1 gear be operated on a to failure and replace basis. Three running units in stand-by would likely require upgrades or replacements in the next five years justified primarily due to obsolescence and no spare parts availability. In-Service Failure funding may be applicable in some cases.

9.2.8.6 Risk Assessment

The 2010/11 Risk Assessment associated with the system had all items as low to medium risk, both from a technological perspective and a safety perspective. The 2017 Risks are little changed.

- Switchgear, turbovisory, Mark V governor systems remain significant risk areas, medium at this point in time, given offset by sparing and management strategies undertaken by the plant. (Ideally replacement would be desirable, but financially infeasible given remaining life).
- OEM support may grow more difficult to obtain.

There is a likelihood that some older items may fail in service, but PM work and redundancy should minimize impacts. A further review of specific critical equipment over the next few years is likely needed if the units are to continue in standby operation after March 2023.

9.2.8.7 Life Cycle Curve and Remaining Life

The "Risk Area" in that Figure has not significantly changed from 2010/2011 condition assessment and 2017 update reports.

The Unit 2 Control Systems (including DCS) Associated with Steam Systems are considered able to reach the March 2023 end of life date for generation, provided regular inspection and service per the station PM plan is maintained. Obsolescence and spare parts unavailability may necessitate some unforeseen equipment replacements/refurbishments.

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

Given the condition historical data reviewed, there is no incremental Level 2 inspection requirement, provided the current inspection and maintenance program for the system is maintained or improved.

9.2.8.9 Capital Projects

The suggested typical capital enhancements for the system would include minor costs for critical control card spares procurement. No major capital is considered justified given limited life and generation level, unless identified by regular PM inspections or during exercising operations. Utilization of In-service Failure funding may be warranted where applicable.

9.2.9 Asset 271317 – Unit 2 Steam Turbine (Chapter 9.2.9 in 2011 Report)

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

9.2.9.1 Description (No major change since 2010/11 and 2017 update Report)

9.2.9.2 History (No major change since 2010/11 and 2017 update Report)

9.2.9.3 Inspection and Repair History (No major change since 2010/11 and 2017 update Report)

A turbine overhaul was completed was in 2014. The turbine major overhauls are now scheduled on a 9-year frequency (generator every six years) with a turbine valves overhaul frequency of 3 years. Vibration monitoring was upgraded in 2013/14. The last valves overhaul was in 2017.

The GE NALCOR Holyrood Unit #2 Minor Valve Inspection 2017 report addressed:

- Disassembly and inspection of upper and lower shell mounted control valves, MSV, CRV, blowdown valve, and NRV and actuators operating cylinders.

The work recommended:

- Thorough NDE and visual inspection of MSV seat and seat seal welds in next inspection (2020)

- Standard set of generator field, stator and exciter electrical tests in next generator inspection

Steam Turbine Inspection History and Projection

T Turbine
G Generator
V Turbine Control Valves

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit #1			T/G/V			V			G/V			T/V			G/V			V
Unit #2		V			T/G/V			V			G/V			T/V			G/V	
Unit #3	V			V			T/G/V			V			G/V			T/V		

Generator O/H seperated from turbine and changed to 6yr cycle

9.2.9.4 Condition Assessment

The condition assessment of the systems has changed little since 2010/11 condition assessment and 2017 update reports. The condition of the equipment is reasonable given the normal mode of 2023, and 2027+ emergency/standby mode.

9.2.9.5 Actions

Based on the condition assessment and the end of generation life, it is recommended that only the PM's and planned inspections be continued.

Current conservative start-up program based on Unit 1 due to Unit 1 vibration issues should be re-examined and subject to findings be reversed.

9.2.9.6 Risk Assessment

The risk assessment associated with the Unit 2 steam turbine is very low, provided ongoing inspections and PM's are followed and repairs made as found.

9.2.9.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change is that the yellowed "Risk Areas" will have shifted towards the 2025+ timeframe range.

9.2.9.8 Level 2 Inspections – Unit 2 Steam Turbine

A generator/valve inspection overhaul planned for 2020 is considered warranted. Given the condition historical data reviewed, the outage should include Level 2 analyses:

- Undertake a stud (for those above 850oF) creep life assessment
- LP L0 borescope

9.2.9.9 Capital Projects

No major capital is considered justified given limited life and generation level. The 2020 inspection/overhaul of generator and turbine valves is warranted.

Future inspections and overhauls in a post steam, cold standby/emergency period - suggested they be repeated every 30,000 equivalent operating hours for the steam turbine (Maximum 12 years), 20,000 equivalent operating hours for generator (10 years maximum) , and 12,000 equivalent operating hours for the valves (maximum 8 years).

9.2.10 Asset 271486 – Unit 2 Cooling Water System - Associated with Steam Systems

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 (No major change since 2010/11 and 2017 update Report)

9.2.10.2 History (No major change since 2010/11 and 2017 update Report)

9.2.10.3 Inspection and Repair History (No major change since 2010/11 and 2017 update Report)

Cooling Water Pumps & Motors, Screens, and Piping Systems

CW Travelling Screens

Travelling screens on Unit 2 have been overhauled in 2015 and internals were new in about 2005. No recent issues have been identified with these units, although floor civil issues are evident and being investigated in 2017. 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 Unit 2 are performing fairly well. No reports were available on the condition of the pumps, but regular maintenance has been kept up and the units should be able to meet March 2021 end of generation life with satisfactory maintenance. Major pump overhauls are scheduled on a twelve-year cycle as indicated in the last west was 2011. 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.

Major Pump Inspection History and Projection

														Post Steam (projected)								
Mean time between O/H	Pumps	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12yr	2 CW Pump East							195												230		
12yr	2 CW Pump West		67												200							
12yr	2 Ext Pump North							152												200		
12yr	2 Ext Pump South					81												175				
	2 Vac Pump North						*								75							
	2 Vac Pump South									50							75					
6yr	2 BF Pump East					160				302						275						300
6yr	2 BF Pump West		180						280						275						300	

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 appear to continue to be in good condition but remain beyond their normal physical life expectation. The east was overhauled in 2016. See 4 kV motor section.

CW Pump Outlet Piping, Valves & Fittings

Outlet Piping, Valves & 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 degrees of exterior corrosion and some patching of the system has been done. It is in need of clean-up and testing for fitness of duty.

Cooling Water System Intake & Discharge

PM inspections are generally on a three-year cycle as per schedule taken from the 2011 report below. 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. An inspection may have been done in 2015, but no record was identified. There have been no obvious issues with the systems. No specific corrosion, spalling, cracks, or fractures were identified, and no patching of the system has been done. An inspection of the CW sump, intake and outfall, and intake and outfall piping are planned in 2020. Attention will be paid to any exposed concrete support in the Sump pits that may have experienced significant concrete loss and exposed the lower layer of reinforcing bars.

9.2.10.4 Condition Assessment

CW condenser intakes were replaced since 2011. There appear to be no significant issues with the system, provided inspections and testing programs, and PM's are undertaken.

9.2.10.5 Actions

Based on the Condition Assessment, the following Actions are recommended.

- Continue concrete intake and discharge pipe inspections– next planned for 2020
- Continue pump/motor inspection PM's
- Maintain critical pump motor parts (coils) available.

9.2.10.6 Risk Assessment

The Risk Assessment associated with the system showed no high-risk level issues in the 2010/11 condition assessment and 2017 update reports.

Currently, that assessment remains valid, with no high-risk issues, provided PM's and inspection schedule maintained.

9.2.10.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" will have shifted towards the 2025+ timeframe range.

9.2.10.8 Level 2 Inspections – Unit 2 Cooling Water System Associated with Steam Systems

A Level 2 analyses of the CW sumps and pipes was planned as part of a larger overall Level 2 inspection project in 2020 that has since been cancelled. Given the condition historical data reviewed, the current inspection and maintenance program for the system should be maintained.

9.2.10.9 Capital Projects

No additional capital projects are anticipated, if

- Spare CW and motor critical parts are readily available.

9.2.11 Large Motors (4 kV)

(Section added in 2017 Condition Assessment Update)

9.2.11.1 Description

The following is a description of the major 4 kV motors in each of the three units. The information provided indicates that in one instance the same motor is installed in two different units (i.e. Units 1 and 2). In addition, the same serial number is applied to two different motors in Units 2 and 3, which cannot be correct. These will require verifying the serial numbers and the data below.

Unit 2 Motors

- Boiler Feed Pump (BFP) East (SN – 8052AA-1): Westinghouse, 3-phase, 4160 volt, 3000 HP, 60 Hz, 3580 rpm
- Boiler Feed Pump (BFP) West (SN – SP23970): ABB, 3-phase, 4160 volt, 3000 HP, 60 Hz, 3583 rpm
- Cooling Water Pump (CWP) East (SN – 9-132171-3, Conflicts Unit 1: Tamper, 3-phase, 4000 volt, 300 HP, 60 Hz, 590 rpm
- Cooling Water Pump (CWP) West (SN – 9-132171-2, Conflicts Unit 3: Tamper, 3-phase, 4000 volt, 300 HP, 60 Hz, 590 rpm
- Condensate Extraction Pump (CEP) North (SN – C04 98044441-001R): US Motor, 3-phase, 4160 volt, 400 HP, 60 Hz
- Condensate Extraction Pump (CEP) South (SN –E06-00063720-100R-01 NRR):US Motor, 3-phase, 4160 volt, 400 HP, 60 Hz
- Forced Draft Fan (FDF) East (SN – 4542364): ABB, 3-phase, 4160 volt, 1502 HP, 60 Hz, 1189 rpm
- Forced Draft Fan (FDF) West (SN – 4542363): ABB, 3-phase, 4160 volt, 1502 HP, 60 Hz, 1189 rpm

Spare Motors

The following spare motors were purchased in 2013. All spare motors are kept in a Pennecon warehouse:

- 2 Boiler Feed Pump (BFP) SCIM, sin# 1026366788, frame MGP500B: 3-phase, 4160 volt, 3000 HP, 60 Hz;
- 1 Forced Draft Fan (FDF) SCIM, sin# 1026842643, frame MGP500C: 3-phase, 4160 volt, 1500 HP, 60 Hz, 1189 rpm.

9.2.11.2 History

The changes since the 2010/11 report are:

Year	Description of Expenditure
2013	Purchase Spare 4kV Motors
2014	Overhaul South Extraction Pump Motor, Unit #2
	Overhaul East FD Fan Motor, Unit #2
2015	Install Variable Speed Drives on Unit #2 FD Fans

	Overhaul West FD Fan Motor, Unit #2
2016	Overhaul Unit #2 East CW Pump Motor,
2017	Overhaul Unit #2 West CW Pump/Motor

9.2.11.3 Inspection and Repair History (No major change since 2010/11 and 2017 C.A and update Report and 2017 update)

Maintenance is carried out on the 4,160 V motors during annual unit outages, in the form of Megger and Bridge tests, air filter changes, and oil sampling and analysis. At the same time there is on-line bearing and winding temperature monitoring and system alarms based on motor current levels. Pennecon rotate spare and megger annually.

The following illustrates items that incurred significant expenditures for maintenance and failures.

Year	Description of Expenditure	Type	G1	G2	G3	Spare
2013	Purchase Spare 4kV Motors	CI	x	x	x	x
2014	Install Variable Speed Drives on Unit #3 FD Fans	CI			x	
	Overhaul West FD Fan Motor, Unit #3	SME			x	
	Overhaul/Rewind East FD Fan Motor, Unit #3	MF			x	
	Overhaul North Extraction Pump Motor, Unit #3	SME			x	
	Overhaul Unit 2 South Extraction Pump Motor	SME		x		
	Overhaul Unit #2 East FD Fan Motor	SME		x		
	Overhaul Unit #1 South Extraction Pump Motor	SME	x			
	Overhaul Unit #1 West FD Fan Motor	SME	x			
	Overhaul Unit #1 East CW Pump Motor	SME	x			
	Install Variable Speed Drives on Unit #1 FD Fans	CI	x			
2015	Install Variable Speed Drives on Unit #2 FD Fans	CI		x		
	Overhaul Unit #2 West FD Fan Motor	SME		x		
	Overhaul Unit #1 East FD Fan Motor	SME	x			
	Overhaul/Rewind Unit #3 East CW Pump Motor	MF			x	
	Overhaul Unit #3 West CW Pump Motor	SME			x	
2016	Overhaul Unit #2 East CW Pump Motor	SME		x		
	Overhaul Unit #1 West Boiler Feed Pump Motor	SME	x			

CI = Capital Investment
SME = Significant Maintenance Expenditure
MF = Major Failure

9.2.11.4 Condition Assessment

The typical life of a 4 kV motor is about 25 to 30 years of operation with regular and diligent maintenance carried out. Holyrood typically consider historic levels equivalent to roughly 40 to 50 years of operation. If the motors are being 2 shifted, that causes advanced aging from thermal cycling. The best type of operation for a motor is continuous on-line operation with minimal start/stops.

For Unit 2, new motors were installed for the CEP, FDF, and BFP's in 1989. It is expected that with annual inspections and maintenance, they should have no issue reaching 2023 or beyond, since they will only have done roughly 34 years of operation. The cooling water (CWP) pump motors are original equipment but are expected to meet a March 2021 target.

Given its operating pattern and start/stop history, it may be that the Holyrood motors may have only accumulated 29 to 34 years of operation over 49 calendar years, considering their historical thermal cycling duty. AMEC Report No. P164200 / RP / 001 - June 2015, HTGS Condition Assessment and Life Extension Study, Report – 4 kV Motor Condition Assessment presents the service life expectation for the 4 kV motors:

CWP	Cooling Water Pumps	expected life to 2021
CEP	Condensate Extraction Pumps	expected life almost to 2030
FDF	Forced Draft Fans	expected life almost to 2030
BFP	Boiler Feed Pump	expected life almost to 2030

9.2.11.5 Actions

Based on the Condition Assessment, the following Actions are recommended:

- Continue to inspect and monitor motor condition and undertake regular maintenance and PM’s.

9.2.11.6 Risk Assessment life Cycle Remaining Life

For Units 1 and 2, new motors were installed for the CEP, FDF, and BFP's in 1989. It is expected that with annual inspections and maintenance, they should have no issue reaching 2023, or beyond, since they will only have done roughly 34 years of operation.

The cooling water (CWP) pump motors in Units 1 and 2 are original equipment, but are expected to meet a 2023 target (AMEC Report No. P164200 / RP / 001)

There was a recommendation that a spare motor to meet the needs of the CWP and CEP might be warranted. The CEP motors of Units 1 and 2 will be in the 34-year range of operation at 2021, so they are expected to achieve the target end date. The CWP motors are already beyond 40 years and could be at risk of not achieving the end date of March 2023 without some operational issues or a failure. Spare coils and bearings were purchased for the CW pump motors (A spare CWP motor expenditure would not be cost effective for only 3.5 remaining years of life)

There was also in 2011 a recommendation to consider fluid couplings or install variable speed drives on the BFP and FDF motors. This was not carried out for the BFP motors, but variable speed drives were installed as a Capital Expenditure on the FDF motors of all three units during overhauls in 2014 and 2015. No further VSD are considered warranted.

9.2.11.7 Level 2 Inspections

Given the condition historical data reviewed, no Level 2 analyses are required provided the current inspection and maintenance program for the system is maintained or improved.

9.2.11.8 Capital Projects

No additional capital projects are required. The failure of one of the CEP motors on Units 1 and 2 would cause an extended outage/derate, however, the likelihood of a failure of one of these is considered low to medium based on the existing condition and number of operating years being under 34 at this time.

10. Unit 3

10.1 Unit 3 – Key Systems

10.1.1 Asset 8298 – Unit 3 Generator

Equipment/components covered in this report are:

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
	8313 #3 Hydrogen System
	8326 #3 Synchronous Condensing System

10.1.1.1 Description

The Unit 3 Generator is a tandem-compound, 2-pole machine, manufactured by Hitachi. It is rated at 177 MVA at 0.85 power factor lagging (i.e. 150 MW), with a terminal voltage of 16 kV. Both the stator and rotor windings are indirectly cooled by hydrogen at 207 kPa (30 psi). The generator has an overload rating of 185 MVA at 310 kPa (45 psi), providing 157 MW at 0.85 pf. It was manufactured in 1979 and went into service in 1980.

In 1986, the generator was modified to operate as a synchronous condenser 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 (pony motor), a Philadelphia Gear Starter Drive Gearpak (Model HL60/9HS), and an SSS Clutches Size 60T SSS Clutch and casing assembly, as well as associated auxiliaries (extension shaft, flexible coupling, hydraulic transmission).

Since 1986 the generator has been operated in the uncoupled synchronous condenser mode for about two months each year in summer. The turbine is disconnected and the synchronous condenser is started up by the starting motor and “disk-pack” clutch attached to the outer-end coupling.

Machine Type	Turbine-Generator	RPM	3600
Voltage/PF	16.0 kV / 0.85	Manufacturer	Hitachi
KVA	177,235	Date Manufactured	1980
Insulation Class	Epoxy mica, F	Serial Number	TFLOO
Cooling	Hydrogen	Stator Slots/ Winding Circuits	60 / 2

The stator winding is indirectly hydrogen cooled, the rotor winding and stator core are directly hydrogen cooled.

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 escaping from the rotating shaft; they 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.

The existing exciter is an ABB Unitrol 6080, it was fully upgraded in 2013. It has not had any modifications since it was commissioned.

The auxiliary systems include:

- 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 service water cooling system and temperature controller to remove the heat from the generator, with a temperature controller to maintain constant cold hydrogen temperature.
- There may be a hydrogen pressure control valve to provide automatic make-up from the bulk hydrogen supply, (at increased hydrogen pressure if overload is required), but it does not appear to be in use at present
- 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 shutdown
- The generator protection 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. Bently Nevada upgrades were completed on all units.

10.1.1.2 History

(No major change since 2010/11 Condition Assessment Report and 2017 update)

10.1.1.3 Inspection and Repair History (No major change since 2017 update report)

In 2011 the synchronous condensing thrust bearing was overhauled. In 2013, the Excitation system was upgraded to Unitrol 6080. In 2016, the steam turbine generator was overhauled, generator rotor was rewound, and a rotor flux probe installed. A special insert section for the generator with a special thrust bearing design was developed and is now in use whenever Unit 3 is operated as a synchronous condenser – substantially reducing the generator vibration in that mode and the resulting generator maintenance issues.

In April to Jul 2016, GE performed a U3 generator (and steam turbine) inspection. Hydro staff removed the turning gear, B coupling and synch skid and inspected the bushing box. GE removed the rotor which was rewound in USA. The #5 and #6 bearing were NDE tested and failed, as did the spare #5 bearing - spare was rabbited and spare #6 was used.

The hydrogen seals were inspected and found out of tolerance and repaired. Bearing #6 and hydrogen seal insulation was replaced.

The stator was inspected and tested. A flux probe was added by IRIS. Hydrogen coolers were inspected and tested and passed. The seal oil and detraining tanks were inspected and accepted.

A U3 valve overhaul was undertaken in 2019 (Unit 3 2019 Valve Overhaul). As part of this work some generator testing was included: power factor with tip up (IEEE 286-2000). No issues identified.

The SSS clutch controller was changed in 2019.

The generator has accumulated roughly 166,000 hours of service life and about 55,000 hours in synchronous condenser mode. The generator and its auxiliary systems are in reasonably good condition for their age. There are no generic or specific design or manufacturing issues regarding the Unit 3 generator. Only normal aging and wear are of concern.

- Stator Core: satisfactory, based on El-CID test results.
- Stator Windings: satisfactory after 32 years, but the re-wedged bars are likely to loosen again.
- Rotor forging: Not known - no NDE checks have been done for 16 years or more.
- Excitation controls and transformer replaced, spare transformer on site.

Rotor

The rotor was recommended to be rewound in previous assessments and this was completed in the spring of 2016. Report CFRG033854 outlines the re-insulation of the winding with the original rotor copper. Other work in the rewind included; replacement of the slip-rings (damaged in an earlier event), refurbishment of radial studs and refurbishing of bore leads. During the initial winding inspection there were no indications of insulation abrasion, migration, excessive contamination, or signs of overheating. The rewind and balancing runs were completed by Alstom and the rotor returned to site. Generator Rotor Final Acceptance Test at Site, CFRG034173, August 2016, confirms that the rotor has been successfully returned to service.

One shorted turn was confirmed in the rotor winding in 2013. The location of the shorted turn had not been identified. It was possibly a singular defect rather than an indication of insulation aging or general insulation degradation.

The rotor incoming inspection to rewind facility indicated a number of mechanical issues with bore plugs, dents, wedge migration and fan blades minor damage. The forging did not indicate any signs of surface overheating of forging or crack initiations on wedge lands. The wedge migration did cause some shallow retaining ring depressions. The modification included application of insulation material pads to prevent similar damage in the future. The retaining rings were inspected, cleaned and liquid penetrant tested.

The inspections of the retaining rings and forging surface inspection on Unit 3 did not reveal any evidence of overheating or electrical sparking on the rings or at wedge to ring interfaces. Such indications would be expected if the rotor were subjected to excessive negative sequence currents. The retaining rings and rotor forging were found suitable for future service.

The generator rotor rewound in 2016 should present no issues for reliable operation out to 2023, likely from 2023 to 2043 in synchronous condensing mode. Regular maintenance and inspections only are recommended for the rotor.

Stator

Insulation deterioration and thermal degradation are one the main concerns for stators. Extended operation at winding temperatures near or above the insulation temperature class the thermal aging rapidly increases and shortens the life of insulation. Visual inspection and on-line PD testing did not indicate any notable stator winding deterioration. The stator winding has been operating well below its insulation thermal class, rendering thermal aging to be unlikely.

The stator winding is considered to be in satisfactory condition and an expectation of operation to 2023 for generation is reasonable. There are no immediate life-limiting issues for the near future and long-term issues are simply age and wear-out related. Rewinding of the stator was recommended previously, but not carried out and would not be recommended for generation purposes only to 2023. For synchronous condensing operation to 2043, generator stator rewind in 2020 to 2021 is considered to be warranted. The plan is to rewind the stator in 2021. Based on these changes and the testing/inspection results on the generator, there are no issues expected to limit the generation life before March 2023, and its synchronous condenser life to 2043.

One location of electrical discharge was identified in the stator between two adjacent bars in different phases. The issue in that location was a lack of clearance between the two bars. PD testing does not indicate this to be a problem.

Loss of stator winding wedge tightness can lead to bar bouncing in the stator slots and insulation abrasion on the slot walls of the core. Further, this can progress to a loss of the stator bar semi-conductive outer coating and slot discharges. In 2007 some relaxation in stator wedge tightness was identified. The stator was re-wedged and no further loosening has been reported. No signs of insulation abrasion or greasing along the slot wedges have been reported. Stator winding contamination was not encountered on the Unit 3 generator, minimizing the possibility winding surface tracking. The on-line PD tests also indicated no sign of damage to the insulation from loose windings.

End winding vibration concerns were considered, but inspection did not indicate any dusting of insulation from vibration induced motion in the end winding. Bump testing also indicated no dangerous natural frequencies.
Visual inspection and a DIRIS test of Unit 3 core indicates it to be in good condition after more than 30-year service. In normal service, severe core degradation is not expected in the service period to 2023 and even beyond.

Some unit 3 generator testing was undertaken in 2019.

T Turbine
G Generator
V Turbine Control Valves

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Unit #1			T/G/V			V			G/V			T/V			G/V			V			T/G/V
Unit #2		V			T/G/V			V			G/V			T/V			G/V			V	
Unit #3	V			V			T/G/V			V			G/V			T/V			G/V		

In 2017 Generator O/H seperated from turbine and changed to 6 yr cycle

10.1.1.4 Actions

Given the recent 2016 rotor overhaul and testing information and results, the primary actions are:

- Continue the generator testing and inspections every six years to verify condition (stator Doble test measurements during the summer outage - necessary to disconnect the neutral bar);
- Continue regular planned/predictive maintenance activities on various generator auxiliaries (hydrogen, oil systems, cooling systems, etc.)
- Monitor the stator 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.
- Check the hydrogen consumption and seal oil consumption for leakage (GE recommends seal oil supply piping flushed annually, to prevent dirt in the emergency by-pass line entering the system);
- Take stator Doble test measurements every 3 years, during the summer outage (it is necessary to disconnect the neutral bar
- Tighten stator bars at some point as normal maintenance. Continued PD measurements and regular planned maintenance is recommended.
- Rewind stator in 2020 to 2021 for synchronous condensing life extension to 2043 considerations. (No rewinds are required for generation end date of March 2023 but warranted for continued synchronous condenser operation to 2043).

10.1.1.5 Risk Assessment

By considering the high risk elements of the Risk Assessment of the 2020/11 Condition Assessment report for the Unit 3 Generator and auxiliaries, it is clear that the high risk issues for the generator and exciter have been dealt with in 2013 and in the 2016 overhaul/inspection both from a technological perspective and a safety perspective. Generator stator rewinding would be desirable if the unit were to continue for synchronous condenser operation for extended periods. The plan is to rewind the stator in 2021.

10.1.1.6 Life Cycle Curve and Remaining Life

The unit is in good condition to achieve a 2023 end of generation life, and with a stator rewind will be well positioned with ongoing inspections and overhauls and PM work to achieve a 2043 synchronous condensing role life. Again, it should be noted that this assessment is valid for normal expected unit service. The consequences of abnormal operation or unpredictable system stress events cannot be predicted. Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2030+ timeframe range.

Given the rotor overhaul in 2016 and recommend stator overhaul in 2020-21, Both should be very capable of meeting a 2023 end of generation date, and also with continued PM work, inspections, overhauls meet a synchronous condensing end of life of 2043.

With the 2013 changes to the exciter controls and transformer, this system will also be in good position of meeting a 2023 end of generation life date, and also with continued PM work, inspections, overhauls meet a synchronous condensing end of life of 2043.

The hydrogen system should be in good position of meeting a 2021 end of life date, and also with continued PM work, focused component replacements, inspections, overhauls also meet a synchronous condensing end of life of 2043.

10.1.1.7 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, including annual megger tests and hydrogen seals checks, and addresses the issues identified in the Issues and Actions list. Maintenance of the current overhaul interval of 6 years is warranted until a stator rewind is completed. A nine-year interval should be considered thereafter.

10.1.1.8 Capital Projects

No major additional capital enhancements for the Unit 3 Generator are recommended, except for the planned Stator Rewind period, if the unit is to operate as a synchronous condenser beyond 2023 and towards 2043. For 2043, it is likely that refurbishment or replacement of the SSD clutch and motor may be needed (assess in 2021+ for 2023-2025+ implementation). It may require periodic upgrades to lesser elements in the hydrogen system that may be identified during PM work.

10.1.2 Asset 8270 – Unit 3 Generator Lube Oil System

Unit #:	**3**
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 - #1 Turbine & Generator
Sub-Systems:	8270 Turbine Oil Systems - #3 Turbine Lubricating Oil (8275) and Jacking Oil Systems (8294)
Components:	8271 Tank & Equip, 8274 Purification, 8276 Flushing Oil Pump, 8277 AC Pump South, 8281 DC Pump, 8546 Aux Oil pump, 8285 Jacking Oil pump

10.1.2.1 Description (No major change since 2010/11and 2017 update Report)

10.1.2.2 History (No major change since 2010/11 and 2017 update Report)

The system has been in service since the unit was placed in service in 1980.

10.1.2.3 Inspection and Repair History (No major change since 2010/11and 2017 update Report)

From CFRG033399_MHC and Oil pumps Overhaul Guntner 2016 Overhaul Unit 3, the work scope included the elements of the hydraulic control system, the lube oil system, and the seal oil system. The systems appear in reasonably good condition. No major outstanding issues. Spare parts going forward could be an issue.

10.1.2.4 Condition Assessment

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 inspected easily because the supply piping resides inside of the oil returns pipe to the oil tank. The 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 frames required.

If this unit is required to support synchronous condenser operation after the generation mode is discontinued in March 2023 then this system will be required to be in operation 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 require more rigorous evaluation at that time. Most will be able with maintenance and replacement to meet the generation end dates of March 2023. Achieving the 2043 synchronous condensing end date will likely require some significant refurbishments and partial replacements at a later date to be determined through future inspections and operating history.

10.1.2.5 Actions

Based on its overall condition assessment, no changes to the C.A and 2017 Reports Recommended Actions are recommended. Maintaining the ongoing PM program inspections and practices for the lube oil system are most critical. Maintenance replacement of some parts of lube oil system required for synchronous condenser operation may be needed for 2020 and beyond based on ongoing inspections.

Assess the requirements for and impacts of quicker start requirements on heater system temperatures in 40-45 ^{o}C range.

10.1.2.6 Risk Assessment

All the risk items in of the 2010/11 Condition Assessment and 2017 update remain as Low Risk, both from a technological perspective and a safety perspective, provided ongoing regular inspections and maintenance PM's are followed.

10.1.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change to the Life Cycle Curve for the Unit 3 Generator Lube Oil System is that the "Risk Area" will have shifted towards the 2030+ timeframe range. The condition of the storage tank, purifiers and coolers may be better assessed if they are inspected in a 2020 timeframe as part of ongoing maintenance/PM programs. These may conclude that some maintenance replacement of some parts of lube oil system may be required for synchronous condenser operation is recommended for post 2020.

10.1.2.8 Level 2 Inspections – Unit 3 Generator Lube Oil System

Given the condition historical data reviewed, no Level 2 analysis of the lube oil system is recommended, provided the current inspection and maintenance program for the system is maintained.

10.1.2.9 Capital Projects

No significant capital enhancements for the system are recommended. Maintenance repairs and minor capital replacements found during inspections should suffice to achieve the 2023 generation end date. For a 2043 synchronous condensing operation, inspections in 2021/22 may result in some recommendations on capital investments in 2025-2030 period.

10.1.3 Asset 8712 – Unit 3 Electrical & Control System Associated with Generators

The requirements for the Electrical & Control Systems associated with the generator for Holyrood 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, Unit 3 Relay Room Protection & Control 8704, Unit 3, Main Controls 8713, Unit 3, Generator Bus-duct and Connections 8750, Unit 3, Battery Chargers 8751, Unit 3, UPS3 Inverter 8757, Unit 3, UPS4 Inverter 8763, Unit 3, Battery Banks 271766, Unit 3 Switchgear, 4160V/600V. 271767, Unit 3, Turbine Supervisory System 301711. Unit 3 DCS 271769 Unit 3 Static Exciter **COMMON** 7197, Common, Stage 1, 129VDC Supply System 271764, Common, Control Cables 271765, Common, Control Cables 309896, Common 600V Metric Plugs

10.1.3.1 Description (No major change since 2010/11 and 2017 update Report)

Asset 8698, Unit 3 Relay Room Protection & Control

<u>Generator G3 Transformer T3, ST3/ST4 and Auxiliaries P & C</u>
Were manufactured by Canadian General Electric and installed in 1979.

<u>Generator G3 and Transformer T3 Protection Panels.</u>
These panels utilize GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications.

<u>Unit Transformer T3 and Unit #3 Protection Panel.</u>

This panel utilizes GE electro-mechanical relays and blocking switches. In addition, they show lockouts, annunciation and indications. New SEL available on generator.

Unit 3 Metering Panel.
This panel contains G3, T3 UST3 MWH meters and stator ground fault protection 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 an alarm annunciation. Modifications were made to adapt the generator, turbine, and boiler controls to the DCS, (Distributed Control System), 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 as to render the doors in the vertical sections unable to be closed, and should connections or conductors require moving or tracing, catastrophic results could happen, taking Unit 3 out of service for an indeterminate time.

- U3 DC Panel was upgraded in 2014-15. Also, some generator protection Schweitzer) and stator gound fault alarms.

Asset 8713, Unit 3, Generator Bus-duct and Connections

The generator bus-duct is a 3ph Isolated Phase Bus c/w PT's and Neutral Cubicle, manufactured by Westinghouse and installed in 1979.

Asset 8750, Unit 3, Battery Chargers

- Unit 3, 129VDC Battery Charger, manufactured by Primax Technologies Inc. and installed in 2011. It is a P4500F-3-125-60. 575V Input, 125VDC Output. Max. Charger output rated 60A.
- Unit 3, 258VDC Battery Charger manufactured by CIGENTEC, Inc. and installed in 2001. Charger is a type C3-250-250PMF3BHRGCU0DS2X6, 600V Input, 258VDC system, 250A Maximum rated charger output.
- Other Information:

- Unit 3, 258VDC Distribution Panel was manufactured by Westinghouse, installed in 1979 c/w breakers, typically FPE type GADC.
- All 258VDC Unit 3 battery chargers were replaced in 2018. 129VDC were in reasonable condition.
- 129 and 258 V distribution panels and breakers were replaced in 2015

Asset 8751, Unit 3, UPS3 Inverter (To be replaced in 2020)

The Inverter is a 9315 Series and was manufactured by Eaton Powerware and installed in 2001.
UPS #3 is expected to be replaced in 2020. 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 @ 77deg F (25deg C).

Other Information: 120/208V, 3ph Distribution Panelboards 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, 3ph, 4W, 225A, 42 circuit.
- Unit 3 WDPF Panel, DP-3 relay room, fed via 125A fused disconnect, Cutler-Hammer, Type PL1, 3ph, 4W, 225A, 42 circuit.

Asset 8757, Unit 3, UPS4 Inverter (To be replaced in 2020)

The Inverter is a 9315 Series and was manufactured by Eaton Powerware and installed in 2001. UPS #4 is expected to be replaced in 2020.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 @ 77deg F (25deg C).

Other Information: 120/208V, 3ph Distribution Panelboards 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, TypePL1, 3ph, 4W, 225A, 42 circuit.
- Unit 3 WDPF Panel, DP-4 relay room, fed via 125A fused disconnect, Cutler-hammer, Type PL1, 3ph, 4W, 225A, 42 circuit. (IR scans every 3 years – usually one per year – not an issue)

Asset 8763, Unit 3, Battery Banks

- Unit 3, 129VDC Battery Bank, 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, 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 Relays.

Figure 10-1 UB3 Switchgear

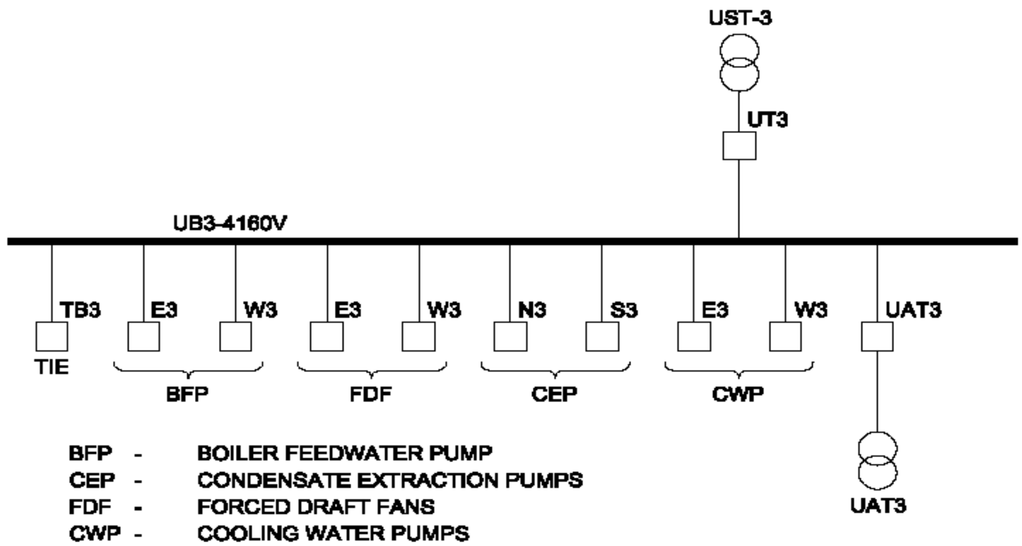
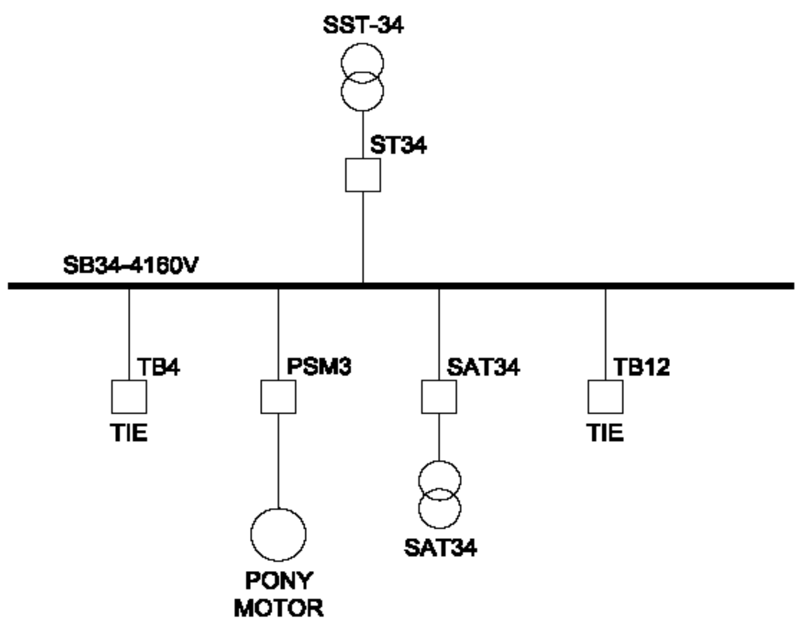


Figure 10-1 SB34 Switchgear



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.

Unit Auxiliary Transformers, UAT3 and SAT34, were manufactured by FPE, and were installed in 1980. Both transformers are 1500/2000kVA, 4160:600/347V, ANAF, c/w tap-changer, +2@2.5%, -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, c/w 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 Nevada and is transferred via a DDX link in the 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.

Asset 301711 Unit 3 DCS

- The DCS was manufacture 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)
  - 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 an ABB Unitrol 6080, it was fully upgraded in 2013.

10.1.3.2 History (No major change since 2010/11 C.A and 2017 update Report)

UPS 3 AND 4 are expected to be replaced in 2020

10.1.3.3 Inspection and Repair History (No major change since 2010/11 and 2017 update Report)

The last Inspection was in 2016. The next inspection would be in 2022.

Unit 3 Exciter was replaced in 2013 with an ABB Unitrol 6080, fully upgraded.

Stage 2 Relay Panel was replaced in 2012.

UPS 3 AND 4 are expected to be replaced in 2020

10.1.3.4 Condition Assessment

The basic DCS, protections, alarms associated with generators and auxiliaries are in fair condition. Little has changed since the Table 10-15 in the 2010/11 Condition Assessment and 2017 update report work. Some maintenance upgrades to the electrical distribution equipment were done in 2019 and likely warranted in 2020-2021 period. Generally speaking, the 4160v and 600v switchgear equipment is reliable as long as proper maintenance as scheduled is completed. Components critical for synchronous condensing operation (if maintained) will need refurbishment or replacement and should be re-examined about every five years or so. Some auxiliary systems such as hydrogen monitoring and switchgear may need replacement or refurbishing, as PM work identifies issues, and primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment. One synch condenser or three running units' operation would indicate that the stage 2 gear would largely need to be replaced over time in the next five years.

Batteries and chargers are likely acceptable to 2023, but replacement may be warranted in 2021-2025 period to achieve a 2043 synchronous condensing end of life. UPS 3 and 4 are planned to be replaced in 2020.

10.1.3.5 Actions – Unit 3 Electrical and Control Systems Associated with Generators

No major additional actions beyond those in the 2010/11 Condition Assessment and 2017 update report are recommended for the electrical and control systems, provided PM work continues and component issues identified are resolved. Some issues that should be examined are:

- By 2021, a review of switchgear and relays and P&C systems for continued synchronous condensing operation through 2043 is warranted.
- Replace 258 kV battery chargers and batteries in 2020-2021 period
- Maintain OEM support and spare parts governor and supervisory
- Complete Verify Bus Duct inspections/tests
- UPS 3 AND 4 are expected to be replaced in 2020
- Replace Stage 2 electrical distribution obsolete equipment in 2021-2023 period
- Upgrade Unit 3 DCS controllers and associated equipment in 2021-2023 period
  - The need for additional actions should be investigated/re-examined about every five years or so, and if the normal mode of plant operation should be modified to extend beyond March 2023. A short term review should be undertaken of the motor controls, relays/switchgear, and some auxiliary systems such as hydrogen monitoring and generator temperature monitoring regarding replacement or refurbishing to extend synchronous condensing life to 2043, primarily due to obsolescence and an inability to obtain parts or from an overall cost reduction due to reduced maintenance costs on newer equipment. Generally, one synch condenser or three

running units operation would indicate that the stage 2 gear would largely need to be replaced over time in the next five years.

10.1.3.6 Risk Assessment

No high risk items were identified in the 2010/11 Condition Assessment and 2017 update report (Table 10-17). Overall the ratings have not changed, provided PM work continues and issues identified addressed.

Where a system is fully or partially required for synchronous condensing, it is likely that PM analysis and some inspections/analysis in 2021-2022 would be warranted to identify specific component change-outs that would be warranted, such as:

- Battery and chargers (current life to 2021, preferred replacement in 2023-2027 period)
- Main controls
- DCS components
- Relays and switchgear
- Gen Bus Duct
- Blr/Turb MCC C2 C3

10.1.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the “Risk Area” will have shifted towards the 2023 to 2025 timeframe range.

The 2010/11 Condition Assessment report for Unit 3 Electrical & Control System Associated with Generators. It suggested that the TSI, Main Controls, Relays, P&C, Bus Duct areas were issues and these haven’t changed for either a 2023 or 2043 end of life.

Other system components should be able to achieve a 2023 end of generation life and may with targeted refurbishments/replacements meet a 2043 synchronous condensing end of life based on updated assessments in 2020-2023.

The Life Cycle Curve – Unit 3 Electrical & Control System Associated with Generators. Indicate that several pieces of Unit 3 equipment may not last much beyond 2023, let alone to 2043. UPS 3 and 4 are expected to be replaced in 2020 and in good condition to the end of synchronous condensing operation in 2043.

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. No Level 2 analyses are currently recommended. Some consideration should be given to spot checks critical equipment over the next few years, including on:

- Bus Duct – inspection and test – no indication done in 2011
- Unit Auxiliary Transformer, UAT3 and SA T34 – inspection and testing
- Cables - – inspection and testing

10.1.3.9 Capital Projects

UPS 3 and 4 are expected to be replaced in 2020. Given the end of generation life of March 2023, no further capital enhancements for Unit 3 Electrical & Control Systems Associated with Generators are recommended, unless identified by PM inspections or during operations, EXCEPT: where a system is fully or partially required for synchronous condensing to 2043. In that case, consideration should be given in 2021-2025 period to capital enhancements including replacement/refurbishment of:

- Relay RM P&C 2021-2022
- Power Centre B 2021-2022
- MCC's 2021-2022
- UPS - UPS 3 and 4 are expected to be replaced in 2020
- Switchgear 2021-2022
- 250 V DC battery and chargers replaced – 2021-2022

Where capital replacements are recommended by PM inspections or operations, it is suggested that consideration be given to the MCC's being replaced as opposed to replacing the starters or protective devices within the starters.

10.1.4 Asset 271678 – Unit 3 Cooling Water Systems Associated with Generators

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

10.1.4.1 Description (Minimal Change since 2010/11 C.A and 2017 update Report)

10.1.4.2 History (Minimal Change since 2010/11 C.A and 2017 update Report)

10.1.4.3 Inspection and Repair History

The last Inspection was in 2016, and the next inspection planned if needed is for 2022).

Hatch along Stantech carried out an inspection of concrete sumps. Further visual inspections of concrete support beams were carried out in 2017 (due to issues with Unit 1 East) which indicated other concrete beams of Units 1,3,4 were in good condition (minor spalling; rusting evident). A Level 2 inspection is planned in 2020 for the Sumps, including as detailed assessment of the Unit 1 East beam.

CW Travelling Screens

Unit 3 Travelling screen internals have not been refurbished and should be inspected in 2020 to determine if needed for synchronous condenser operation to 2043. 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 corroded state but 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. Regular maintenance has been kept up and the units should be able to meet 2021 timelines with satisfactory maintenance. West CW pump was overhauled in 2017. Major pump overhauls are scheduled on a twelve-year cycle. Pump 3 East may have to be done in 2021, but the temporary CW pump using the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty may be adequate interconnections between Units 1 to 3 CW systems allowing them to provide back-up for this purpose may also suffice.

CW Pump Motors – Motors are electrically tested every year (following PM process). Both west and east CW motors were overhauled in 2015 and the east pump motor was rewound. See 4 kV motor section.

CW Pump Outlet Piping, Valves & Fittings

Outlet Piping, Valves & Fittings from the pump to the inlet of the 64" concrete piping that goes underground to the unit condensers has generally experienced significant degrees of corrosion and some patching of the system has been done.

Cooling Water System Intake & Discharge

The 36" and 64" CW intake and discharge concrete piping that goes underground to the unit condensers has in past periodically been pumped out and walked down by station staff, although not recently. Unit 3 is not dewatered due to concerns over its stability. A video was undertaken showing some cracking and issues with steel pipe connections. No detailed engineering evaluations and NDE work appears to have been undertaken.

Inspections should be planned going forward in 2020 to 2021 on a three to five year cycle for fitness for service. An inspection is planned as part of Level 2 Condition Assessment work in 2020.

10.1.4.4 Condition Assessment

Condition Assessments have not changed substantially since 2010/11 C.A and 2017 update Report (Table 10-22). There remain issues with concrete CW piping and pit stoplogs and outfall structure, as well as travelling screen and wash system degradation. An inspection is planned as part of Level 2 Condition Assessment work in 2020.

The systems can likely be made to function satisfactorily for March 2023 generation end of life, but work on a plan to address the requirements for synchronous condensing to 2043 regarding pumps, travelling screens will be required for post 2023 life (taking into consideration interconnections, etc.).

10.1.4.5 Actions

The actions identified in the 2010/11 Condition Assessment 2017 update Report largely still apply, and include:

- Continue PM and inspections
- Perform underwater inspection of Unit 3 concrete CW piping, intakes, outfalls, stop logs.
- Perform Level 2 on Aux Cooling water piping.
- Assess replacement of Aux Cooling water pumps

10.1.4.6 Risk Assessment

The Risks identified in the 2010/11 Condition Assessment 2017 update Report all remain "low" (particularly for March 2023 generation end of life) but largely still applicable for synchronous condensing operation post 2021. Review of needs will likely be required about 2022.

10.1.4.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2022 to 2025 timeframe range.

The Life Cycle identified in the 2010/11 Condition Assessment and 2017 update report for the various elements of the Unit 3 Cooling Water Systems Associated with Generators has not changed much. Pumps, valves and travelling screens remain issues for post 2023 generation end of life (but interconnection redundancy may address).

The curve indicates that most elements of the Unit 3 Cooling Water Systems Associated with Generators can reach the end date of 2023 for generation, but not the 2043 end date for synchronous condensing. 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.

10.1.4.8 Level 2 Inspection Requirements and Costs

As in the Level 2 Inspection Requirements of the 2010/11 Condition Assessment C.A and 2017 update report and given the condition historical data reviewed, no Level 2 analyses is required, provided the current inspection and maintenance program for the system is maintained. A visual inspection of the concrete pipes may be warranted.

For a 2043 end date for synchronous condensing, a Level 2 analysis consisting of a remote visual inspection is likely warranted in 2021-2023.

10.1.4.9 Capital Projects

No capital enhancements for Unit 3 Cooling Water Systems Associated with Generators are warranted at this time for a 2023 end date. For a 2043 synchronous condensing life, a Level 2 assessment may conclude that the capital enhancements may be required in 2020-2030 related to items such as:

- Refurbish Travelling screens
- Replace auxiliary cooling water pumps and motors.

10.2 Unit 3 – Lower Priority Systems (2011 Report Identification)

10.2.1 Asset 8336 – Unit 3 Boiler System

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, Economizer, tubing and headers
	8339, Linking piping (boiler internals l)
	8351, Furnace water circuit 8344, Steam drum, 8351, Downcomers and feeder piping as required 8351, Lower Waterwall headers 8351, Waterwall tubing 8351, Upper Waterwall headers, and riser piping as required
	8360, Superheater; headers and tubing
	8384, Reheater; headers and tubing
	Safety Valves
	8460, Furnace combustion systems; burners, fans, air heaters
	8337, Furnace structural, hangers and casing

10.2.1.1 Description (No change since 2010/11 C.A and 2017 update report)

10.2.1.2 History

The boiler system has been a significant source of unreliability in 2012 to 2017. Hence in 2017 it was actually considered a key system, if not the key system. It remains a key piece in 2020 to March 2023. It may be utilized as an auxiliary steam source in the period after March 2023.

10.2.1.3 Inspection and Repair History (Minimal change since 2010/11 C.A and 2017 update Report)

Minor and Major overhauls (last major 2018 and 2019) alternate every year. The boiler expansion joints were replaced in 2014. Major Level 2 inspection and repair projects were implemented on Units 1 through 3 in 2012 to 2017 as a result of the previous 2010/11 Condition Assessment and significant tube failures and reliability losses in 2015. This has resulted in sections of the boiler that are experiencing significant wall thickness loss and/or cracking being replaced. Results of these are documented in several recent reports.

In 2017 significant sections of the economizer and air preheater also underwent deep cleaning to improve air flow and combustion.

In the AMEC 2017 Condition Assessment Level 2 Report, the following were indicated:

- Boiler tubes experience fireside corrosion and erosion
- Reliable operation to 2021 conclusion for Units 1 and 2 did not include Unit 3
- Only accessible areas were inspected, but only one location (south bend 9th floor RH tubes) showed significant wall thickness loss from 2016
- Rest of inspections deferred to 2018, acceptable
- Spare tubing purchase and inspection near furnace wall lugs recommended

In addition, replica and PAUT inspection of the U3 main steam at the West Upper terminal point weld was carried out consistent with 3-year cycle. The wall thicknesses were slightly lower but identified as of no integrity concern. Volumetric inspections, replication and magnetic particle inspections found no indications of creep damage. Wall thicknesses on both sides of the weld were above pressure based minimum requirements. It was recommended that the 3-year cycle continue --- i.e. next in 2020/21.

B&W also engaged Wayland Engineering to conduct a metallurgical examination of a length of waterwall tube from the east bullnose, baffle wall knee section. Previously boiler water conductivity was found much higher than typical, raising concerns with boiler tube condition. There were minimal issues with pitting or wall thickness or internal deposits (for tubes in service >10 years). No cause was identified as far as was reported.

In B&W Boiler 2018 Condition Assessment Report, Team ultrasound examination reports on Unit 3 are summarized as follows:

- Unit 3 – Economizer inlet header (borehole ligament cracks) - Status: completed
- Unit 3 – Site 3-1: HP heater #6 bypass 1st elbow D/S of tee bypass branch (wall thinning/FAC) – Status: completed

- Unit 3 – Site 3-2: HP heater #6 bypass last bypass elbow (wall thinning/FAC) – Status: completed
- Unit 3 – Site 3-4 BFP low flow line connection to main run elbow and pipe (wall thinning/FAC) – Status: completed
- Unit 3 – Site 3-3 West BFP discharge (wall thinning/FAC) – Status: completed
- Unit 3 – BFP discharge Flow Element 3554 (wall thinning/FAC) – Status: completed
- Unit 3 – SSH tubes 8.5th floor overhead tube (wall thinning) – Status: completed
- Unit 3 – Feedwater pipe upstream of 45o bend U/S of Y connection (wall thinning/FAC) – Status: not completed?
- Unit 3 – SSH tubes. Tube bends at furnace wall lug connections (wall thinning) – Status: completed
- Unit 3 – RH tubes 9th floor overhead tube (wall thinning) – Status: completed
- Unit 3 – RH tubes. Tube bends at furnace wall lug connections (wall thinning) – Status: completed

Team ultrasound examinations results and the 2018 inspection indicated the following:

- Rate of wall loss unchanged, with areas of concern being below (remeasure and repair/replace as appropriate):
  - Site 3-1 1st elbow D/S of Tee Bypass branch (left bend)
  - Pad weld of flow element 3554
  - Flow element 3554 – U/S of weld
    - Cracking of SH vestibule components are increasing and may be due to vestibule shifting in direction not adequately supported – undertake a structural assessment corrections needed
    - The economizer inlet header does not appear to be suffering borehole ligament cracking (as suggested previously)
    - The PSH and SSH tubes did not show signs of excessive wall loss, but leading-edge RH tubes appear to be approaching end of life (order longer lead bent leading edge tubes)
    - Tube to header weld inspections should be continued where warranted for remainder of remaining life

Boiler Inspections History and Projections to 2021

Ma Major
Mn Minor

Boiler Overhaul Schedule

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Unit #1	Ma	Mn	Ma	*	Ma	Mn	Mn	Ma	Mn	Ma	Ma	Mn			
Unit #2	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma	Mn	Ma	Ma			
Unit #3	Ma	Ma	Mn	Ma	Mn	Ma	Mn	Mn	Ma	Ma	Mn	Ma			

*No Boiler Overhaul for U1 in 2013

10.2.1.4 Condition Assessment

Boiler and high-pressure piping systems Level 2 inspections, and associated mitigation/repairs (in additional to annual boiler maintenance program) have been ongoing since the 2011 report. Major work has been undertaken in various sections of the boiler such that most of the boiler is currently in reasonably good condition. The condition of the Boiler Stop Valves (identified in 2011 as having no recent information on condition, and no condition assessment work done to 2016) is more an issue because of the failure and removal of the Unit 1 Boiler Stop Valve.

10.2.1.5 Actions

Based on the condition assessment and work done on the units since 2011, the following actions are recommended:

- Maintain annual PM's and inspections/overhauls.
- Continue program of detailed Level 2 inspections and tests as per Level 2 Boiler assessments. Including: Superheater Front Horizontal Space Outlet Header; Reheater Outlet Header
- Inspect Boiler Stop Valve
- Inspect Boiler Blowdown Tanks.

10.2.1.6 Risk Assessment

Since the 2011 issue of the Level I report, all of its "High" risk items have been inspected per the recommended Level II scope. Additionally, several "Medium" and "Low" risk areas were also inspected.

Generally, it is considered that the Unit 3 boiler is in reasonably good condition to reach a March 2023 end of normal generation life and able to meet end of emergency/standby generation life in March 2027

Boiler overhauls are planned for each year of operation to 2023 and further Condition Assessments to 2019 (focused Level 2 recommended to be continued to end of normal operating life). As in previous years, the expectation is that recommended follow-up inspections from the Level II assessments will be completed. The two major risks are creep in high temperature components and FAC in the feedwater lines. These are both potentially "High" risk areas. Thermal transformation of the high temperature piping and headers has been observed and repairs and replacements have been performed on the feed water piping. Both these areas will continue to require inspection (and repairs as found).

Other degradation mechanisms require monitoring to ensure that they do not continue to progress (e.g. corrosion in the water circuit), or that any progression of damage does not threaten the component integrity (e.g. economizer inlet headers, downcomer penetrations).

The primary High-Risk Level items are:

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Space Outlet Header	Creep and thermal fatigue	3	D	High
Reheater Outlet Header	Creep and thermal fatigue	3	D	High

Component	Major Issues	Likelihood	Consequence	Risk Level
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	High
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	High

Others are medium or low risk. A comprehensive list is included in NSS Report

Component	Major Issues	Likelihood	Consequence	Risk Level
Economizer Inlet Headers	Thermal/Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion, FAC.	3	B	Med
Economizer Outlet Headers and Link Piping	Mechanical Fatigue Cracking, Corrosion-Fatigue Cracking, Corrosion.	1	B	Low
Upper WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking in flat end welds. Corrosion	2	B	Low
Riser Tubes	Corrosion, Corrosion Fatigue	3	B	Med
Lower WW Headers	Thermal fatigue cracking, Corrosion-fatigue cracking. Corrosion	3	B	Med
Feeder Tubes	Corrosion, Corrosion Fatigue	3	B	Med
Downcomers	Thermal/Mechanical Fatigue Cracking at the header support locations	3	B	Med
Steam Drum	Thermal fatigue cracking, Corrosion-fatigue cracking	3	C	Med
Superheater Steam Cooled Walls Outlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Inlet Header	Thermal fatigue.	1	B	Low
Superheater Rear Horizontal Spaced Outlet Header	Creep and thermal fatigue	1	C	Low

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Support Tube Inlet Header	Creep and thermal fatigue	3	C	Med
Superheater Front Horizontal Platen Inlet Header	Creep and thermal fatigue	1	C	Low
Reheater Inlet Header	Thermal fatigue.	1	B	Low
Superheater Link Piping and Attemperator	Thermal/Mechanical Fatigue, Corrosion-Fatigue, Corrosion.	3	C	Med
Economizer Tubes	External corrosion and corrosion-fatigue.	1	B	Low

Piping System	Damaging Mechanism	Likelihood	Consequence	Risk Level
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	High
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	High

Hot and Cold reheat steam piping were considered to be in good condition and to be low to medium risks. Other risk issues include the Boiler Stop Valve and Boiler Blowdown Tanks both of which should be inspected. Other issues with boiler systems were largely mitigated during 2015 to 2019.

10.2.1.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025+ timeframe range. High risk issues in the 2010/11 Condition Assessment study have been mitigated to beyond 2020 by the Level 2 Inspection and Repair work that has been ongoing. Some uncertainty remains around the Boiler Stop Valves and Boiler Blowdown Tanks. Others will continue to be addressed through additional Level 2 work.

10.2.1.8 Level 2 Inspection Requirements and Costs

Regular maintenance and follow-up on high risk items will become increasingly important for safe and reliable plant operation. Station programs credited here and other regular inspections must be continued and the findings addressed. Changes to the programs or regular inspections can impact the likelihood of a failure event, if not properly mitigated.

Given the condition historical data reviewed, the required Level 2 analyses, assuming that the current plant inspection and maintenance program is maintained or improved, are those periodic Level 2 as per current 2016 Level 2 program results. In particular Level 2 work should continue on those elements identified in the risk analysis as "high" (and repeated below) through end of normal generation life of March 2023 and as required to meet end of emergency/standby generation life in March 2027.

Component	Major Issues	Likelihood	Consequence	Risk Level
Superheater Front Horizontal Space Outlet Header	Creep and thermal fatigue	3	D	High
Reheater Outlet Header	Creep and thermal fatigue	3	D	High
Feedwater Discharge	• Flow Accelerated Corrosion (FAC), • Thermal/Mechanical Fatigue Cracking, • Corrosion-Fatigue Cracking, • Corrosion	3	D	High
Main Steam	• Thermal/Mechanical Fatigue • Creep, Creep-Fatigue • Corrosion	3	D	High

From the B&W Boiler 2018 Condition Assessment Report, the following activities were suggested based on previous AMEC Level 2 work:

Table 4-3 Amec Inspection Recommendations for NLH HTGS Unit 3

Component/Location	Inspection Dates	Inspect for	Methodology
Economizer Inlet Header	2018	Borehole ligament cracks	Visual and PAUT
RH Inlet Header	None before 2022		
RH Outlet Header	2019	Wall thinning *Based on 2016 B&W NOTIS inspection*	UT
SSH Inlet Header	None before 2022		
SSH Outlet Header	None before 2022		
WW Lower Header	None before 2022		
WW Upper Header	None before 2022		

Component/Location	Inspection Dates	Inspect for	Methodology
High Pressure Feedwater Header	2021	Wall thinning / FAC	UT grid
PSH Outlet Header	None before 2022		
Economizer Inlet Header Piping	-		
Feedwater Piping	2018	Wall thinning / FAC	UT grid
		1. *HP Heater No. 6 Bypass 1st elbow downstream of tee bypass branch*	
		2. *HP Heater No. 6 Bypass last bypass elbow*	
		3. *Upstream of 45 degree bend upstream of Y connection*	
	2019	Wall thinning / FAC	UT grid
		1. *Elbow upstream up Economizer inlet*	
		2. *Downstream of 45 degree bend upstream of Y connection*	
	2020	Wall thinning / FAC	UT grid
		Straight pipe adjacent to Y connection	
Link Piping to Attemperator	None before 2022		
Boiler Feed Pump Piping	2018	Wall thinning / FAC	UT grid
		1. *BFP low flow line connection to main run elbow and pipe*	
		2. *West BFP discharge*	
		3. *BFP discharge Flow Element 3554*	
	2019	Wall thinning / FAC	UT grid

Component/Location	Inspection Dates	Inspect for	Methodology
		BPF discharge bend upstream of Heater No. 5 inlet	
Cold Reheat Steam Piping	None before 2022		
Hot Reheat Steam Piping	None before 2022		
Main Steam Piping	None before 2022		
RH Attemperator Refill Piping	2018	Wall thinning / FAC	UT
		1. Downstream of 1st angle valve	
		2. Main line immediately upstream of the 1st drain connection	
	2019	Wall thinning / FAC	UT
		Immediately upstream of the control valve	
	2020	Wall thinning / FAC	UT
		First drain line between the two control valves	
SSH Attemperator Piping	None before 2022		
Steam Drum	None before 2022		
Supports	2018 & 2020	Failures / cracking	Visual / MT
Economizer Tubes	None before 2022		
Lower Vestibule Feeder Tubes	-		
Lower WW Header Feeder Tubes	None before 2022		
WW Tubes	None before 2022		
PSH Tubes	None before 2022		
SSH Tubes	2018	Wall thinning	UT

Component/Location	Inspection Dates	Inspect for	Methodology
		1. *8.5th floor overhead tube* 2. *Tube bends at furnace wall lug connections*	
RH Tubes	2018	Wall thinning 1. *9th floor overhead tube* 2. *Tube bends at furnace wall lug connections*	UT
Riser Tubes	None before 2022		

From 2019 B&W Inspection and Condition Assessment

Table 4-3 Inspections on HGTS Unit 3

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
3	Header	RH Outlet Header	Thermal fatigue crack (2014)	2019	No indications observed	2022	MT
3	Header	SSH Outlet Header		2019	No indications observed	2022	MT
3	Header	RH Inlet Header Tube Stubs	Cracks (2018)	2019	No indications observed	2022	MT
3	Header	SSH Outlet Header Tube Stubs	Fatigue	2019	Early stage signs of fatigue damage	2022	MT
3	Header	Economizer Inlet Header	Pitting (tubes)	2018	No thermal fatigue cracks but pitting on tube IDs	2022	Visual (PAUT if cracks found)
3	Pipe	FAC Site 3-1	FAC (2012)	2019	ASME min in 8 years	2023	UT grid
3	Pipe	FAC Site 3-2	FAC (2012)	2019	ASME min in 7 years	2022	UT grid
3	Pipe	FAC Site 3-3	FAC (2012)	2018	Pad weld in 2015; ASME	2023	UT grid

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
					min in 10 years		
3	Pipe	FAC Site 3-4	FAC (2012)	2018	ASME min in 19 years	2027	UT grid
3	Pipe	FAC Site 3-5	FAC (2012)	2015	Reinspect in 4.4 years	2020	UT grid
3	Pipe	Feedwater BFP Discharge Flow Element 554	FAC (2015)	2018	Pad weld in 2018; Reinspect in 6 years	2024	UT grid
3	Pipe	Main Steam Piping		2017	Microstructural degradation and minor thickness loss; Reinspect in 3 years	2020	Replica, PAUT, MT
3	Pipe	Main Steam East Boiler Link		2015	Wall thickness was well above minimum wall	2025	UT
3	Pipe	Cold Reheat Bleed Steam Line		2015	No indications observed	2025	MT
3	Tubes	RH Leading Edge Bends	Wall Thinning (2017)	2019	21 bends pad welded in 2017; 18 bends pad welded in 2019; remaining 21 bends have thinned considerably and will likely need pad welded	2020	UT
3	Tubes	Boiler Floor Tubes	Wall Thinning	2019	Some bend extrados locations are approaching	2021	UT

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
					recommended repair/replace thickness		
3	Tubes	WW Tubes around Burner Openings	Wall Thinning	2019	Several locations pad welded and several more just above the repair/replace thickness	2020	UT
3	Tubes	Waterwall Tubes	Wall Thinning / pitting	2019	Some pitting and ID scale destabilization due to upset chemistry event	2025	Metallurgical Assessment
3	Tubes	Lower Vestibule Waterwall Feeder Tubes	Pitting	2015	PAUT found pits but unknown if pits are active	2020	Visual (PAUT if pits appear active)
3	Tubes	Economizer Tubing	Wall Thinning, Creep	2016	Wall thickness above repair/replace criteria	2025	UT
3	Tubes	Primary Superheater Tubing	Wall Thinning, Creep	2018	Wall thickness above repair/replace criteria	2025	UT (NOTIS RLA)
3	Tubes	Secondary Superheater Tubing	Wall Thinning, Creep	2018	Wall thickness above repair/replace criteria	2025	UT (NOTIS RLA)
3	Tubes	Reheater Tubing	Wall Thinning, Creep	2018	Wall thickness at some locations fell below	2021	UT (NOTIS RLA)

Unit	Component Type	Component	Degradation	Last Inspection	Results	Next Inspection	Inspection Methodology
					repair/replace criteria		

Also given the Condition Assessment and Repair work that has been done between 2011 and 2017, Level 2 inspections and/or repairs should also be undertaken on:

- Inspect Boiler Stop Valves
- Inspect Boiler Blowdown Tanks

10.2.1.9 Capital Projects

Significant improvements have been made in the Boiler Systems in 2011-2019. No specific additional capital enhancements for Unit 3 Boiler System are warranted at this time, other than continued Level 2 inspections and associated mitigation measures to end of life.

Consideration should be given to expenditures associated with using Unit 3 to supply auxiliary steam for quicker start purposes, especially during period after March 2023, taking advantage of its existing economizer recirculation system, steam turbine gland steam HP turbine warming system, and its fuel management system. It may involve the retrofit of a couple of the smaller, mechanical atomization type burners that can be swapped for the existing burners to maintain auxiliary steam in quantities required while firing the heavy fuel oil.

10.2.2 Asset 8611 – Unit 3 Feed Water System HP Heat Exchangers (Chapter 10.2.2 in 2011 Report)

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
	8849 #3 Boiler Feed Pump West

10.2.2.1 Description (No major change since 2010/11 C.A and 2017 update Report)

10.2.2.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.2.3 Inspection and Repair History

The high-pressure feedwater heaters were assessed in 2011 as “Medium” and “Low” risk. 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. Condensate drains and HP heater trip level were installed in 2015. Given the short generation life, no long term commitment (life-cycle management plan) is in place to diagnose and track all the failures to identify possible remedial actions or likely warranted.

The Unit 3 HP feedwater heat exchangers HP-4, HP-5 and HP-6 were installed in December 1997 and hence have accumulated fewer operating hours than other HTGS HP feedwater heat exchangers except Unit 2 HP-5. However, their operating life is more than EPRI recommended interval of 5 years for NDE inspections.

The boiler feed pumps have a spare stage available for reliability purposes. Vibration monitoring was upgraded in 2015. Regular inspections and tests and overhauls of pumps and motors have been maintained

It was noted in U3 W July 2013 document that U3 W was swapped out in July 2013 (last time was 2005); in U3 E May 2014 document that U3 E was swapped out in May 2014 (last time was 2008); and in U3 E/W July 2016 document that steam leak repair was needed on both in July 2016.

10.2.2.4 Condition Assessment

No issues identified. The HP heaters and boiler feed pumps and motors are expected to meet the 2023 generation end of life. The BFP and motors are tested and inspected, and the pumps have a spare stage available. The HP Htrs give no indication of issues and are able to address single failure issue in short term. The High-Pressure feedwater discharge piping had Level 2 done and mitigated. There is a spare BFP Motor.

10.2.2.5 Actions

Based on the Condition Assessment, the Recommended Actions for Unit 3 Feed Water System HP Heat Exchangers and Boiler Feed Pumps/Motors are primarily to maintain ongoing inspections and PM. No Level 2 inspections have been done, but not high priority. No Actions beyond ongoing inspections and PM are recommended

10.2.2.6 Risk Assessment

Both from a technological perspective and a safety perspective, the Risk Assessment associated with the HP Heaters and Boiler Feed Pump/Motors is low.

Component	Tag Name	Major Issues	Likelihood	Consequence	Risk Level
Unit #3 HP Feedwater Heater #4	HP-4	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	2	B	Low
Unit #3 HP Feedwater Heater #5	HP-5	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	2	B	Low
Unit #3 HP Feedwater Heater #6	HP-6	SCC, FAC, Thermal/ Mechanical Fatigue, Corrosion-Fatigue	2	B	Low

10.2.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025 to 2030 timeframe range for normal operation.

The 2010/11 Condition Assessment Life Cycle Curves for the Unit 3 Feed Water System HP Heat Exchangers and Boiler Feed Pumps/Motors largely still apply. The equipment should be capable of operating satisfactorily until generation end of life in March 2023 and 2027 emergency/cold standby mode.

10.2.2.8 Level 2 Inspection Requirements and Costs

Given the condition assessment and historical data, no further Level 2 analyses are required, premised on that the current inspection and maintenance program for the system is maintained.

10.2.2.9 Capital Projects

Refurbishment/overhaul of the East and West Boiler Feedpumps are planned for 2020 and 2021, in essence one year past their normal overhaul interval. No additional capital enhancements for the systems beyond these overhauls are recommended, provided the spare volute and a spare motor are available and vibration monitoring had been installed and is being monitored.

10.2.3 Asset 8571 – Unit 3 Feedwater System – Deaerators (Chapter 10.2.3 in 2011 Report)

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 (No major change since 2010/11 C.A and 2017 update Report)

10.2.3.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.3.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

A Level 2 inspection was performed on deaerator in last five years.

10.2.3.4 Condition Assessment

The deaerator and deaerator storage tanks were assessed in 2011 as "Medium" and "Low" risk in the Level I report. The storage tanks are inspected every year as part of regular maintenance. Local repairs are regularly performed but there have been no significant issues noted. The Unit 3 deaerators are considered in good condition and able to achieve generation end of life in March 2023, and to operate in cold standby/emergency mode through 2027+.

10.2.3.5 Actions

Based on the Condition Assessment, no Actions are recommended for the Unit 3 Feedwater - Deaerator System. Maintain regular PM's/inspections.

10.2.3.6 Risk Assessment

The Unit 3 Feedwater - Deaerator System are low to medium risk and able to meet end of generation life in March 2023. None are a high level or life limiting risk.

Component	Major Issues	Likelihood	Consequence	Risk Level
Deaerators	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	3	B	Medium
Deaerator Storage Tanks	Corrosion-Fatigue, Thermal Fatigue, Corrosion & FAC	2	B	Low
Deaerators/ Storage Tanks	Corrosion-Fatigue and Thermal Fatigue,	1	D	Medium

10.2.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025 to 2030 timeframe range.

The 2010/11 Condition Assessment Life Cycle Curve for the Unit 3 LP Feedwater System - Deaerators has not significantly changed. All equipment is expected to be able to meet the March 2023 end of generation life, and to operate in cold standby/emergency mode through 2027+.

10.2.3.8 Level 2 Inspection Requirements and Costs

Given the condition assessment and historical data reviewed, no additional Level 2 analyses are required. A Level 2 inspection of the deaerator with internals removed that was originally planned for 2020 to check for flow accelerated corrosion should be assessed.

10.2.3.9 Capital Projects

No additional capital enhancements for the system are recommended.

10.2.4 Asset 8546 – Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers

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

10.2.4.1 Description (No major change since 2010/11 C.A and 2017 update Report)

10.2.4.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.4.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

Leak tests are generally performed on the LP feedwater heat exchangers during annual outages, but records of these were not obtained. If a leak is found, the leaking tube is plugged. The tube plugging maps and history were not available. Other than that, no inspection was carried out. During interview with site staff, it was mentioned that there are no performance issues with the LP feedwater heat exchangers.

The south extraction pump was overhauled in 2015. A spare condensate extraction motor was procured and available. No Level 2's performed, but spot checks on some tanks.

10.2.4.4 Condition Assessment (No major change since 2010/11 C.A and 2017 update Report)

The Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered in good condition and able to achieve generation end of life in March 2023 or 2027+ emergency/cold standby mode.

10.2.4.5 Actions

Based on the Condition Assessment, no Actions are recommended for the Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers. Maintain regular PM's/inspections.

10.2.4.6 Risk Assessment

There has been no significant change in the Risk Assessment associated with the system from 2011 report, both from a technological perspective and a safety perspective. There are no high priority issues. The Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers are considered low risk, able to achieve end of generation life and able to meet end of generation life in March 2023 or 2027+ emergency/cold standby mode.

10.2.4.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025+ timeframe range.

The 2010/11 Condition Assessment Life Cycle Curve for the Unit 3 Feedwater System - Low Pressure Feedwater Heat Exchangers has not significantly changed. All equipment is expected to be able to meet the March 2023 end of generation life and the 2027 emergency/standby mode.

10.2.4.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, No Level 2's inspections are required, provided ongoing inspection and maintenance program and PM's continue.

10.2.4.9 Capital Projects

No additional capital enhancements for the system are suggested.

10.2.5 Asset 271677 – Unit 3 Condenser

Unit #:	**3**
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 - #1 Turbine & Generator
Sub-Systems:	8223 # 3 Turbine & Condenser
Components:	271677 #3 Condenser

10.2.5.1 Description (No major change since 2010/11 C.A and 2017 update Report)

10.2.5.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.5.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

Condensers are in good shape for their 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.

No indications after 2008 inspection report that shell and hotwell are not in good condition. No additional information on water boxes and the epoxy lining that were in good condition in 2008. A Level 2 inspection of the condenser waterboxes is planned for 2020.

10.2.5.4 Condition Assessment

The condenser and auxiliaries appear in good condition. There had been an indication that refurbishment or replacement of the vacuum pumps and motors might be warranted. Given the remaining generation life to March 2023, this is not likely an issue that cannot be addressed through ongoing PM processes. In Aug 2017, repairs were made to the Condensate Extraction Pumps (Cond Extra pump – Aug 2017 repairs)

10.2.5.5 Actions

Based on the condition assessment, no further actions are recommended for the condenser beyond:

- Continue PM's. Pump/motor checks.
- Undertake a condenser waterbox material thicknesses check (repair if/as required).
- Overhaul vacuum pumps and motors, as PM's warrant.

10.2.5.6 Risk Assessment

The risk assessment associated with the condenser and auxiliaries is considered low, assuming normal PM processes are followed. An inspection/wall thickness check of elements of the water boxes would be desirable, but not critical.

10.2.5.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 Update Report, the primary change to the Life Cycle Curve is that the yellowed "Risk Area" for the Vacuum Pump would have shifted to 2020-2022.

The curves indicate that the remaining life (RL) of the Unit 3 Condenser can reach the desired life (DL) March 2023 end date for generation. The exception to this might be the vacuum pumps/motors, but this is relatively minor issue that can be readily addressed as a maintenance issue if/as it occurs.

10.2.5.8 Level 2 Inspections

Given the condition historical data reviewed, a Level 2 analyses of the condenser waterbox/tubesheet is considered warranted.

10.2.5.9 Capital Projects

No new capital enhancements for the Unit 3 condenser are considered warranted, subject to waterbox thickness checks. Vacuum pump/motor maintenance refurbishment or replacements may be needed as PM's warrant.

10.2.6 Asset 8777 – Unit 3 FD Fans (& System)

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
Components:	8782 #3 Boiler FD Fan System 8392 #3 Boiler FD Fan East 8393 #3 Boiler FD Fan West 8404 # 3Boiler Steam Air Heater East 8405 # 3 Boiler Steam Air Heater West 8410 # 3 Boiler Main Air Heater East 8411 # 3 Boiler Main Air Heater West
	8438 # 3 Boiler Gas Passes 8452 # 3 Boiler Sootblowing System 8455 # 3 Retractable Sootblowers 8456 # 3 Rotary Sootblowers 8791 # 3 Air Heater Sootblowers 253030 # 3 Boiler Waterlances

10.2.6.1 Description (No major change since 2010/11 C.A and 2017 update Report)

Variable Speed Drives to the FD fan motors were added in 2015 to provide incremental combustion control. There was a major expenditure in 2016 on fuel storage and handling system as a result of damages incurred using poor quality fuel under a new fuel supply contract.

10.2.6.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.6.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

The equipment is checked annually as part of the boiler inspection program. Both the east and west FD fans motors were overhauled in 2014 and the east FD fan motor rewound in 2014. Variable Speed Drives to the FD fan motors were added in 2015. Spare 4 kV motors were purchased in 2013.

Poor quality oil (high silica, alumina, susceptible to separation) was utilized in 2015. It caused significant damage to fuel handling systems (heaters, filters, burner tips, pumps) as well as tank deposition requiring cleaning. The fuel specification was subsequently modified, and the fuel improved.

Annual boiler inspections/overhauls (alternating minor and major) and repairs ongoing with OEM.

Major Level 2 inspections and repairs in 2014 to 2017, including significant surface replacements experiencing tube thinning and tube failures.

The east air heater hot end basket was replaced in 2011. Both air preheaters were deep cleaned in 2017.

From HTGS 2017 Unit # 3 FD Fan NDT Reports June 14, 2017, it was identified that during the yearly Magnetic Particle examination of Unit 3 East FD fan components revealed some issues that were repaired.
The east and west air preheaters were inspected in 2017 (A031090 - Field Service Report - Babcock Wilcox JL Hydro Holy Rood Station - JKRIZON - 6-5-17 Unit 3). The cold end baskets were replaced. The cold side of the hot end baskets were also inspected and found 50% pluggage of A compartment baskets in 3E assembly and D compartment of #W assembly.

Also replaced were the hot and cold end radial and circumferential seals, the cold end circumferential seal support angles, the rotor post seals, the hot end sector plate liners. The unit were leveled, and the stroke of the soot blowers verified to cover entire rotor. The air preheater was considered in good condition structurally as were the pinion racks.

The east fan bearing has a vibration issue. Fans will be internally inspected in 2020.

Fuel Oil Firing

Major parts of the fuel oil filters and heaters were replaced/refurbished in 2015 as a result of the purchase and use of a higher silica/alumina/vanadium oil that year. Fuel changes and the new equipment have improved the situation. Recent reports regarding the condition of the light and heavy oil systems were not available or reviewed. However, the systems had visually appeared to be in reasonable condition. 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.

In 2019 significant deposition was noted in unit fuel filters and heaters. The material was very difficult to clean, and a Quebec company's proprietary process was applied to clean out heater tubes. It appears that fuel oil separation and deposition has occurred resulting in a gooey solid coming from both the main and day tanks. (Note that the main tank suction heaters have been covered especially top surfaces with a very hard coating that is no doubt reducing their thermal effectiveness.

10.2.6.4 Condition Assessment

The condition assessment of the systems is as follows.

- FD Fan and motor in reasonable condition, spare motor available.
- Air Htr and economizer were cleaned in 2017 and in good condition.
- Hangers reset.

- The oil system which had issues in 2015 requiring major refurbishment have been resolved through an improved oil specification/procurement and system refurbishments/replacements. Although another but different problem appears to have arisen in 2019.

The soot blowing system still somewhat limited and it could be improved in terms of coverage and efficiency. More frequent use of APH sootblowing also appears warranted (continuous versus once per day or per shift). No significant capital investment is foreseen.

The Unit 3 FD Fans (& System) are considered in good condition to meet March 2023 generation end of life, but that could change if unusual operating requirements should result in performance deterioration (cycling, two-shifting, excessive low or high load operation)

10.2.6.5 Actions

There are no high priority risks to address at this time. Based on the Condition Assessment and discussions, the following Actions are recommended for the – Unit 3 FD Fans (& System).

- Continue PM's and OEM annual work
- Monitor delta in combustion air pressure to time additional APH/Econ cleaning.
- More use of APH sootblowing
- Inspection of FD fans and APH's internally in 2020
- Assess fuel plugging issues for solution for near and longer term
- For faster starts, assess temperature in standby maintain 50 oC versus current temperature switch at 85-90 oC (more consistent with 0.7% sulphur oil vs 2.5% sulphur oil historical basis).
- For low flow, assess use of a low flow control valve circuit.

No other high priority items remain from 2011 or since that time, provided annual boiler work and PM's are continued.

10.2.6.6 Risk Assessment

The risk assessment associated with the Unit 3 FD Fans (& System) are considered medium, given the number of repairs/refurbishments undertaken, assuming normal PM/OEM processes are followed. Additional APH/economizer pluggage work may be warranted.

10.2.6.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update Report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025 to 2030 timeframe range.

With the addition of a spare FD fan motor and VFD's the 2010/11 Condition Assessment Life Cycle Curve for the Unit 3 FD Fans (& System) has significantly improved. The Unit 3 FD Fans (& System) are expected to be able to meet the March 2023 end of generation life and cold standby/emergency mode to 2027+.

10.2.6.8 Level 2 Inspection Requirements and Costs

Given the condition assessment and historical data reviewed, no additional Level 2 analyses are required. Level 2 inspections of the FD fans and airpreheaters were planned for 2020 as part of larger Level 2 project. Continued inspections associated are considered warranted (fuel system plugging; APH and FD fan inspections; APH cleaning).

10.2.6.9 Capital Projects

No additional capital enhancements for the system are recommended, subject to findings in PM's warrant.

10.2.7 Asset 8448 – Unit 3 Stacks and Breaching (Chapter 10.2.7 in 2011 Report)

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 271682 – Stack Breeching

10.2.7.1 Description (No major change since 2010/11 C.A and 2017 update Report)

The stack is constructed from reinforced concrete and contains a steel liner with some sections of the liner stainless steel and some carbon steel.

10.2.7.2 History (No major change since 2010/11 C.A and 2017 update Report)

Stack repairs (liners, breeching) were completed after 2012

10.2.7.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

The station has as part of its PM program and due to regulatory issues, been diligent in its inspections of the stack from a structural perspective and in making the suggested repairs. Overall, the conditions of all of the stack, the breeching and ladders and joints are good. No major cracking or structural issues seem to have arisen. The condition of the current linings and cap seem to suggest that the unit has not been operating below the dew point, due to the unit seldom running at full load or below 50% MCR. Also, the annual number of starts and stops is quite low.

Stack inspections in 2015 (Report in October 2015 by Industrial Chimney Maintenance/B&W) indicated:

- Concrete column was in fair condition
- Had several long vertical cracks throughout full height, but not very large in width

- Several open construction cracks and horizontal hairline cracks allowing moisture penetration into annular space (should be addressed to minimize more rapid deterioration)
- paint in paint fairly aged and thin condition, poor for selected areas
- Rain hood in good condition
- Lightning protection had several defects requiring repair
- Access ladder and anchor bolts in good condition. Bottom safety rail section (200ft) replaced, but top 160 ft section original version so two different trolleys/lanyards required
- Two access platforms in satisfactory condition
- Aviation lights in good condition. Two light bulbs burnt and replaced
- Breaching exterior at chimney connection had visible corrosion and deteriorated paint and on breaching roof before chimney connection
- Annular space from 0 to 200 ft level had numerous moisture stains indicating moisture penetration. Liner exterior at base had defective paint and corrosion.
- Liner interior in good condition, with sloped floor in satisfactory condition.
- Breaching interior refractory brick as liner connection in fair condition. One horizontal sampling rod disconnected at one end.

Stack inspections in 2017 by Industrial Chimney Maintenance/B&W indicated that some recoating might be warranted, but generally that the concrete stacks are in reasonably good condition and are expected to be able to make the March 2023 generation end date.

The stack was also inspected in 2018 (2415-18 Report Stack #3 (Low Res) Dec 21, 2018). It included an external inspection of concrete shell, internal inspection of liner, and of annular space from mid-level to ground.

Observations

During the review of the inspection notes and photographs, the following issued were observed with the chimney:

- Numerous hairline cracks and open construction joints are found throughout the entire concrete column exterior.
- The external paint on the concrete column is in poor condition
- The lightning protection system down-lead on the north side of the stack is in poor condition at the base of the chimney and is disconnected from the stainless-steel rain hood. It also has a break in the lead sheath below the top of the chimney.
- Numerous lightning protection system anchors are defective or missing in the top 10’ of the chimney.
- There are no access hand / foot irons on the rain hood or along the column wall to access the rain hood for inspection.
- There are two different safety rail systems installed on the access ladder above and below the mid-level platform.
- Two aviation light bulbs are burned out at the top platform level.
- There is corrosion visible on the cover at the top of the breaching where it connects to the chimney.
- The exterior of the liner above the base in the annular space has defective paint and is corroded.
- There is a buildup of bird waste on the annular space floor.
- A horizontal sampling rod is disconnected at one end in the breaching entry.

Recommendations
After a review and study of the information obtained during the inspection, we recommend that the following repairs be carried out on the chimney at the earliest possible convenience:

- Grind out and fully expose all cracks and open construction joints throughout the exterior concrete shell and seal.
- Thoroughly high pressure (min 7000 psi) wash down and prepare the entire surface of the chimney exterior and apply a sealer coat to all exposed concrete and apply two coats of quality protective paint specifically designed for coastal environments.
- Repair all defective LPS anchors in the 10' of the chimney.
- Supply and install stainless steel hands irons on conical section of rain hood to provide access for inspection around the rain hood.
- Replace burned out aviation lightbulbs at top platform level.
- Thoroughly prepare and repaint the breaching rood at the chimney connection.
- Repair or replace sampling rod at breaching entry interior.
- Remove all debris from base of annular space install bird screening entry to the ground.

10.2.7.4 Condition Assessment

The stack is inspected every three years. An inspection was undertaken in 2017 and 2018. A coating was suggested in the 2017 inspection but has been deferred given the generation end of life originally of 2021. The stack is considered able to meet the end of normal generation life of March 2023 and able to meet end of emergency/standby generation life in March 2027, but re-coating seems warranted to protection shell integrity.

10.2.7.5 Actions

Based on the condition assessment in 2017 and 2018, the following actions are recommended:

- Continue stack regulatory inspections in 2020 and beyond
- Consider undertaking re-coating in 2021 to 2023 period, if stack inspections verify requirement or if generation extension possible

From B&W/ICM Report – April 2018, a quote was prepared based on a repair scope of work for the #3 stack is based on the stack inspection completed by ICM in 2015. Subsequent to completing the review of the inspection reports it was advised that the stacks would only remain in operation for another five years at most. Based on this information, the repair scope of work originally quoted for the #1 and #2 stacks was reduced to immediately necessary repairs to the concrete column and stack accessories. The coating of the stacks or altering the ladder safety rail, nor the work on the breaching brick were included.

When then advised that the stacks could possibly continue in operation to as late as 2023 and would likely be left standing for many years beyond that date, revised quotes that included applying a new coating to the exterior of each of the stacks to help protect the concrete from moisture penetration were added. The scope of work for each of the stacks quoted below includes these revisions.

#3 Stack Repair – Scope of Work

- Grind out and fully expose all cracks and open construction joints throughout the exterior concrete shell and seal.
- Thoroughly high pressure (min 7000 psi) wash down and prepare the entire surface of the of the chimney exterior and apply a sealer coat to all exposed concrete and apply two coats of quality protective paint specifically designed for coastal environments.
- Repair all defective LPS anchors in the top 10' of the chimney.
- Replace burned out aviation light bulbs at top platform level.
- Thoroughly prepare and repaint the breaching roof at the chimney connection.
- Repair or replace sampling rod at breaching entry interior.
- Remove all debris from base of annular space and install bird screening at all openings in the chimney.
- Prepare and paint the exterior of the liner from below the breaching entry to the ground.
- Chimney #3 Repairs = $170,600

10.2.7.6 Risk Assessment

The stack is not considered a high risk for generation end of life in March 2023. Nevertheless, consideration of the stack coating recommended in the 2017/18 inspections if verified in a future inspection should be completed, likely in 2020/21 period, especially if use for auxiliary heating or emergency use is contemplated, or if it is likely to continue to be left in place for an extended period..

10.2.7.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change is that the Existing Breech risk area would disappear, and the others would not likely change.

The Unit 3 Stack is considered able to reach the desired life (DL) of March 2023 end date for generation, and likely well beyond, provided current inspections and maintenance are maintained.

10.2.7.8 Level 2 Inspections – Unit 3 Stack and Breaching

No Level 2 analyses are considered to be required, provided the current plant regulatory inspections and maintenance programs are maintained or improved. Continue stack inspections and monitor degradation of stacks and liners. Undertake stack re-coating, likely in 2021-2023.

10.2.7.9 Capital Projects

No additional capital work is recommended, except stack re-coating is recommended in 2021-2023 period.

10.2.8 Asset 8712 – Unit 3 Electrical and Control Systems (including DCS) Associated with Steam Systems (Chapter 10.2.8 in 2011 Report)

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 309901. #3 Boiler Protection and Control 8238, #3 Turbine Governor System

10.2.8.1 Description (No major change since 2010/11 C.A and 2017 update Report)

10.2.8.2 History (No major change since 2010/11 C.A and 2017 update Report)

Some of Stage 2 129 and 258 V distribution panels and breakers replaced in 2015.

10.2.8.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

The relay panel was replaced in 2012.

10.2.8.4 Condition Assessment

The condition assessment of the systems is largely the same as in 2010/11:

- The Turbine Governor and Turbovisory system has limited life but is managed with OEM support in place for turbovisory. No recent issues causing outages.
- DCS main controls – refurbished
- Switchgear and P&C may be an issue but have been managed through redundancy and spares and OEM support. Additional spares have been procured. Some refurbishment/replacement is likely appropriate in next three years for synchronous operation to 2043

10.2.8.5 Actions

Based on the Condition Assessment, the following Actions are recommended.

- No major changes to existing systems.
- Maintain existing systems with no major changes – supplement spares, securing ongoing maintenance agreements with OEM's
- Some of the electrical distribution equipment was scheduled for replacement in 2019.

The need for additional actions should be investigated/re-examined about every five years, especially if the normal mode of plant operation should be modified to extend beyond March 2023. Obsolescence and an inability to obtain parts may necessitate some replacements or refurbishments, less likely an overall cost benefit assessment due to reduction due to reduced maintenance costs on newer equipment. Generally, one synch condenser operation would indicate that stage 2 gear not related to synchronous condenser operation be operated on a to failure and replace basis. Three running units in stand-by would likely require upgrades or replacements in the next five years justified primarily due to obsolescence and no spare parts availability. In-Service Failure funding may be applicable in some cases.

10.2.8.6 Risk Assessment

The 2010/11 Risk Assessment associated with the system had all items as low to medium risk, both from a technological perspective and a safety perspective.

The current Risks have little changed. Switchgear, turbovisory, governor systems remain risk areas, perhaps higher at this point in time, but addressed through spares and OEM support.

10.2.8.7 Life Cycle Curve and Remaining Life

The Unit 3 Control Systems (including DCS) Associated with Steam Systems are considered able to reach the March 2023 end of life date for generation, provided regular inspection and service per the station PM plan is maintained. Obsolescence and spare parts unavailability may necessitate some unforeseen equipment replacements/refurbishments.

10.2.8.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, there is no incremental Level 2 requirement, provided the current inspection and maintenance program for the system is maintained.

10.2.8.9 Capital Projects

Suggested capital enhancements are considered for the system are limited to:

- Minor costs for spares procurement.
- Replacement of electrical distribution equipment in 2021 to 2023 likely not justified for limited generation life and level, unless identified by regular PM inspections or during exercising operations. Utilization of In-service Failure funding may be warranted where applicable but assess in context of value in synchronous condensing operation to 2043 if applicable.

10.2.9 Asset 271675 – Unit 3 Steam Turbines

Unit #:	**3**
Asset Class #	BU 1296 - Assets Generations
SCI & System:	8194 - #3 Turbine & Generator
Sub-Systems:	271675 #3 Steam turbine
Components:	8196 Main Steam Chest
	8201 HP Turbine
	8211 IP Turbine
	8217 LP Turbine

	8230 Front Standard

10.2.9.1 Description (No major change since 2010/11 C.A and 2017 update Report)

10.2.9.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.9.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report Report)

The last turbine overhaul was completed was in 2016 and valve overhaul in 2019. The turbine overhauls are currently scheduled every 9 years (next would have been 2025) and the generator every six years (next in 2022) and the valve overhaul at every 3-year interval (next 2022) remains unchanged.

In March to July 2016 (2016 Unit 3 Valve Overhaul), the valve inspection was done as part of a major turbine/generator overhaul. The valve inspection included the upper and lower control valves, the combined reheat intercept valves, the extraction steam non-return valves, the main stop valves, and the emergency blowdown valve. The inspection identified any issues identified and made the appropriate repairs and/or /replacements. There were no major outstanding issues.

In 2019, there was a valve inspection (2019 GE Valve Overhaul). The scope included:

1. Disassemble, clean and inspect, and reassemble all 4 control valves
2. Phased Array Ultrasonic Test on steam chest
3. Disassemble, clean and inspect, and reassemble 2 main stop valves
4. Disassemble, clean and inspect, and reassemble LHS and RHS combined reheat valves
5. Disassemble, clean and inspect, and reassemble blowdown valve
6. Disassemble, clean and inspect, and reassemble all 8 non-return valves

A number of items were found and repaired/replaced. One item was the existing cracks in the steam chest. These were inspected using Phased Array Ultrasonic Test (PAUT) by Acuren and showed crack depth had grown by 7mm in 2016 to 12 mm in 2019. GE recommended that it be left as is, but that it be tested again during the next exposure and to get further recommendations.

Steam Turbine Inspection History and Projection

T Turbine
G Generator
V Turbine Control Valves

Post Steam (projected)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit #1			T/G/V			V			G/V			T/V			G/V			V
Unit #2		V			T/G/V			V			G/V			T/V			G/V	
Unit #3	V			V			T/G/V			V			G/V			T/V		

Generator O/H seperated from turbine and changed to 6yr cycle

10.2.9.4 Condition Assessment

The condition assessment of the systems has changed little since 2010/11, with the exception of the steam chest cracking. The condition of the equipment is reasonable given the end of generation life in March 2023, subject to the findings of the growth of the steam chest crack issue.

10.2.9.5 Actions

Based on the condition assessment and the end of generation life, it is recommended that the steam chest cracks be re-inspected in 2022, but otherwise that only the regular PM's and planned inspections be continued.

10.2.9.6 Risk Assessment

The risk assessment associated with the Unit 3 steam turbine is very low, with the exception of the steam chest cracking, provided ongoing inspections and PM's are followed and repairs made as found.

10.2.9.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2025 to 2030 timeframe range, with the exception of the steam chest cracking.

10.2.9.8 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, the following Level 2 analyses are required and could be undertaken during 2022 generator and turbine valves inspection.

- steam turbine steam chest crack growth testing
- turbine studs operating above 850^{0}F be given a creep life assessment
- LP L0 borescope testing

Thereafter undertake a steam turbine inspection/overhaul and valve overhaul in 2027 if cold standby/emergency mode continues. Thereafter, undertake these consistent with 30,000 equivalent operating hours (max 12 years) for steam turbine and 12,000 equivalent operating hours (max 8 years) for valves.

10.2.9.9 Capital Projects

No capital enhancements for the system are recommended, with the possible exception of steam chest cracking repairs if the 2022 inspections recommend that. Undertake the steam turbine valve overhaul in 2022 if normal life is extended beyond 2023 or if cold standby/emergency mode is adopted. Thereafter undertake the roughly every 6 years afterward, and a major steam turbine overhaul in 2027, and every 10 years beyond that date.

10.2.10 Asset 271768 – Cooling Water System - Associated with Steam Systems

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 (No major change since 2010/11 C.A and 2017 update Report)

10.2.10.2 History (No major change since 2010/11 C.A and 2017 update Report)

10.2.10.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

Asset 8649/8650 CW Travelling Screens

Unit 3 Travelling screen internals were inspected and repaired in 2018 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 W Wash Water Pumps and Motors

Externally these are generally in a very 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

CW Pumps on all units are performing fairly well. No reports were available on the condition of the pumps, but regular maintenance has been kept up. The East unit was (U3 CW East Sep 2010 repair; swap Aug. 2017) swapped out in 2017. The units should be able to meet March 2023 end of generation life with satisfactory maintenance. Major pump overhauls are scheduled on a twelve-year cycle (last East was 2010; last west was 2017). Major pump overhauls are scheduled on a twelve-year cycle as indicated in the chart below

Major Pump Inspection History and Projection

													Post Steam (projected)									
Mean time between O/H	Pumps	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
12yr	3 CW Pump East	75												200								
12yr	3 CW Pump West								211												230	
12yr	3 Ext Pump North								143												200	
12yr	3 Ext Pump South						68												175			
	3 Vac Pump North			x			~~x~~						175									
	3 Vac Pump South											175										
6yr	3 BF Pump East					145						250						300				
6yr	3 BF Pump West				138						335						300					

A temporary CW pump was being used in the existing Unit 4 intake to supply smaller quantities of cooling water to Unit 3 for Synchronous Condensing duty. Further 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). They were both overhauled in 2015 (East motor also rewound). See 4 kV motor section

CW Pump Outlet Piping, Valves & Fittings

Outlet Piping, Valves & Fittings from the pump to the inlet of the 64” concrete piping that goes 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 testing for fitness of duty.

Asset 8647/6678 Cooling Water System Intake & Discharge

The 36” and 64” CW intake and discharge concrete piping that goes underground to the unit condensers has periodically been pumped out and walked down by station staff. An inspection would normally have been done in 2013 and again in 2016, but there is concern that if dewatered that there could be some collapse. No detailed engineering evaluations and NDE work has been undertaken.
An inspection of the CW sump, intake and outfall, and intake and outfall piping are planned in 2020. Attention will be required the exposed concrete support in the East Sump pit that has experienced significant concrete loss and exposed the lower layer of reinforcing bars.

10.2.10.4 Condition Assessment

The condition assessment of the systems is that that the system should be acceptable to end of generation life in March 2023, if inspections and testing programs and PM’s continue. A configuration for the cooling water for synchronous generation also appears viable well beyond March 2023.

10.2.10.5 Actions

Based on the Condition Assessment, the following Actions are recommended.

- Continue pump/motor inspection PM’s

- Concrete intake and discharge pipe remote inspections

10.2.10.6 Risk Assessment

The Risk Assessment associated with the system is that all are low risk issues, provided PM's and inspection schedule maintained as follows, both from a technological perspective and a safety perspective.

10.2.10.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve is that the "Risk Area" will have shifted towards the 2020 to 2025 timeframe range.

10.2.10.8 Level 2 Inspections – Unit 3 Cooling Water System Associated with Steam Systems

No Level 2 analyses are required. A Level 2 analyses of the CW sumps and pipes was planned as part of a larger overall Level 2 inspection project in 2020 that has since been cancelled. Given the condition historical data reviewed, the current inspection and maintenance program for the system should be maintained.

10.2.10.9 Capital Projects

No capital enhancements for the system are anticipated, but subject to planned level 2 inspections in 2020, and except the currently planned upgrade of the wet well stop logs in 2020.

10.2.11 Large Motors (4 kV) (Added here in 2017 Condition Assessment Updated)

10.2.11.1 Description (No major change since 2010/11 C.A and 2017 Update Report)

The following is a list of the major 4 kV motors. There may be some discrepancies in serial numbers and the data below that would need to be verified if used.

Unit 3 Motors

Boiler Feed Pump (BFP) East (SN 316613-2): Hitachi, 3-phase, 4000 volt, 2350 HP, 60 Hz, 3550 rpm
Boiler Feed Pump (BFP) West (SN 316613-1): Hitachi, 3-phase, 4160 volt, 2350 HP, 60 Hz, 3550 rpm
Cooling Water Pump (CWP) East (SN 9-132171-2) Conflicts with Unit 2: Hitachi, 3-phase, 4000 volt, 390 HP, 60 Hz, 584 rpm
Cooling Water Pump (CWP) West (SN 9-132171-4): Hitachi, 3-phase, 4000 volt, 390 HP, 60 Hz, 584 rpm
Condensate Extraction Pump (CEP) North (SN 366467-2): Hitachi, 3-phase, 4160 volt, 350 HP, 60 Hz, 1760 rpm
Condensate Extraction Pump (CEP) South (SN 366467-1): Hitachi, 3-phase, 4160 volt, 350 HP, 60 Hz, 1760 rpm
Forced Draft Fan (FDF) East (SN 1-1754074): Westinghouse, 3-phase, 4000 volt, 1500 HP, 60 Hz, 1188 rpm
Forced Draft Fan (FDF) West (SN 2-1754074): Westinghouse, 3-phase, 4000 volt, 1500 HP, 60 Hz, 1188 rpm
Synchronous Condenser Pony (SN 1-6114-60062-1-1): Siemens, 3-phase, 4000 volt, 1600 HP, 60 Hz, 1780 rpm

Spare Motors

The following spare motors were purchased in 2013. All spare motors are kept in a Siemens warehouse.
1 Boiler Feed Pump (BFP): SCIM, sin# 1026842642, frame MGP450D, 3-phase, 4160 volt, 2350 HP, 60 Hz

10.2.11.2 History (No major change since 2010/11 C.A and 2017 update Report)

The changes since the 2010/11 report are:

Year	Description of Expenditure
2013	Purchase Spare 4kV Motors
2014	Install Variable Speed Drives on Unit #3 FD Fans
	Overhaul West FD Fan Motor, Unit #3
	Overhaul/Rewind East FD Fan Motor, Unit #3
	Overhaul North Extraction Pump Motor, Unit #3
2015	Overhaul/Rewind Unit #3 East CW Pump Motor
	Overhaul Unit #3 West CW Pump Motor

10.2.11.3 Inspection and Repair History (No major change since 2010/11 Report)

Maintenance is carried out on the 4,160 V motors during annual unit outages, in the form of Megger and Bridge tests, air filter changes, and oil sampling and analysis. At the same time there is on-line bearing and winding temperature monitoring and system alarms based on motor current levels.

The following illustrates significant expenditures incurred for maintenance and failures.

Year	Description of Expenditure	Type	G1	G2	G3	Spare
2013	Purchase Spare 4kV Motors	CI	x	x	x	x
2014	Install Variable Speed Drives on Unit #3 FD Fans	CI			x	
	Overhaul West FD Fan Motor, Unit #3	SME			x	
	Overhaul/Rewind East FD Fan Motor, Unit #3	MF			x	
	Overhaul North Extraction Pump Motor, Unit #3	SME			x	
	Overhaul Unit 2 South Extraction Pump Motor	SME		x		
	Overhaul Unit #2 East FD Fan Motor	SME		x		

Year	Description of Expenditure	Type	G1	G2	G3	Spare
	Overhaul Unit #1 South Extraction Pump Motor	SME	x			
	Overhaul Unit #1 West FD Fan Motor	SME	x			
	Overhaul Unit #1 East CW Pump Motor	SME	x			
	Install Variable Speed Drives on Unit #1 FD Fans	CI	x			
2015	Install Variable Speed Drives on Unit #2 FD Fans	CI		x		
	Overhaul Unit #2 West FD Fan Motor	SME		x		
	Overhaul Unit #1 East FD Fan Motor	SME	x			
	Overhaul/Rewind Unit #3 East CW Pump Motor	MF			x	
	Overhaul Unit #3 West CW Pump Motor	SME			x	
2016	Overhaul Unit #2 East CW Pump Motor	SME		x		
	Overhaul Unit #1 West Boiler Feed Pump Motor	SME	x			

CI = Capital Investment
SME = Significant Maintenance Expenditure
MF = Major Failure

10.2.11.4 Condition Assessment

The typical life of a 4 kV motor is about 25 to 30 years of operation with regular maintenance carried out. The Holyrood motors may have only accumulated 25 years of operation over 40 years, considering their historical thermal cycling duty. AMEC Report No. P164200 / RP / 001 - June 2015, HTGS Condition Assessment and Life Extension Study, Report – 4 kV Motor Condition Assessment presents the service life expectation for the 4 kV motors:

- CWP Cooling Water Pumps expected life to 2021+
- CEP Condensate Extraction Pumps expected life almost to 2030
- FDF Forced Draft Fans expected life almost to 2030
- BFP Boiler Feed Pump expected life almost to 2030

All 4 kV Unit 3 motors will be approximately 45 years old by 2023 but are likely to achieve a March 2023 end of generation life. Some maintenance issues or a failure may occur, but with annual inspections and maintenance, they should make end of life. A spare motor shared with Units 1 and 2 may be desirable for the Unit 3 CWP and CEP. (Spare motors for the FDF and the BFP were purchased in 2013.)

10.2.11.5 Actions

Based on the Condition Assessment, the following Actions are recommended:

- Continue to inspect and monitor motor condition and undertake regular maintenance and PM's

10.2.11.6 Risk Assessment/Life Cycle/Remaining Life

The risk assessment associated with the 4 kV motors of Unit 3 is considered low. They should achieve the generation end date of March 2023, provided ongoing inspection//maintenance and PM's are followed and repairs made as found.

10.2.11.7 Level 2 Inspection Requirements and Costs

Given the condition historical data reviewed, no Level 2 analyses are required, provided the current inspection and maintenance program for the system is maintained.

10.2.11.8 Capital Projects

No capital enhancements for the system are recommended, provided PM and inspections are followed and addressed.

11. Common Systems

11.1 Common Systems – Key Systems

11.1.1 Asset 1325: 5990 to 6052 – Switchyard Switchgear

Unit #:	Common
Asset Class #	BU 1325 – Holyrood Switchyard
Components:	5990-6007, Switchyard Breakers 6008 - 6041, 275789 Motorized Disconnect Switches 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, as are generally shown in the same order as the Present State Asset List. The Single Line diagrams attached in Chapter 4 provide the electrical locations in the switchyard:

- 230kV Breakers - B12L17, B2L42, B1L17.
- 138kV Breakers - B8L39.
- 69kV Breakers - B7L38, B7L2, B6L3, B7T5, B6T10
- 230kV Motorized Disconnects - B11T5, B15T6, B15T7, B12T10-1, B15T8, B12B15-1, B12B15-2, B12L18-1, B12L18-2, B13B15-1, B13B15-2, B1T1, B3L18-1, B3L18-2, B2T2, B3B13-1, B3B13-2, B3T3, B12L17-1, B12L17-2, B12L42-1, B12L42-2, B1B11-1, B1B11-2, B1L17-1, B1L17-2, B2B11-1, B2B11-2, B2L42-1, B2L42-2:
- 138kV Motorized Disconnects - B8T6, B8T7, B8T8

11.1.1.2 Inspection and Repair History

Many of the pieces of equipment have been or will be replaced/refurbished as part of larger breaker and disconnect upgrade projects, at least partially due to System power outages experienced in 2014 and 2015.Their history and condition are outside of the scope of this current update.

The equipment is regularly tested and inspected based on Hydro's PM protocol. It is functional and in reasonable condition.

Essentially all of the equipment will be required through to 2043 so it will all at some point require extensive refurbishment and/or replacement.

11.1.1.3 Condition Assessment

The condition assessment of all of the components is outside of the scope of this current update. Newer items replaced since 2014 as part of the Breaker and Disconnect Upgrades are in good condition and will last, with regular PM and maintenance, to at least 2043. Older equipment not yet replaced/refurbished since 2014 will likely be required through to 2043 and will at some point require extensive refurbishment and/or replacement as part of future breaker and disconnect upgrade projects.

11.1.1.4 Actions

The breakers and disconnects will be replaced or refurbished as part of overall TRO Breaker and Disconnect Upgrade projects between 2017 through 2030. No details are provided herein but can be obtained through TRO Asset Managers in Bishop's Falls.

11.1.1.5 Risk Assessment

The Risk Assessment associated with these pieces of equipment is outside of the scope of this update. Information can be obtained through TRO Asset Managers in Bishop's Falls.

11.1.1.6 Life Cycle Curve and Remaining Life

Newer items replaced since 2014 as part of the Breaker and Disconnect Upgrades are in good condition and will last with regular PM and maintenance to at least 2043.

Older equipment not yet replaced/refurbished since 2014 will likely be required through to 2043 and will at some point require extensive refurbishment and/or replacement as part of future breaker and disconnect upgrade projects.

11.1.1.7 Level II Inspections

No specific Level II inspections are within the scope of this update. Ongoing inspections are undertaken by TRO as part of Asset Management and PM's.

11.1.1.8 Capital Projects

Capital investments are outside of the scope of this update and are planned and undertaken by TRO as part of Asset Management and PM's.

11.1.2 Asset 1325L 5975 to 5989 – Transformers

Transformers are generally outside of the scope of this update.

The transformers associated with the Holyrood units are:

Unit #:	**1,2,3, Common, Holyrood Switchyard**
Asset Class #	BU 1296 – Assets Generation BU 1297 - Assets Commons BU1325 Assets Holyrood Switchyard
Components:	BU1325, 5975, Unit 1, T1 Power Transformer BU1325, 5976, Unit 2, T2 Power Transformer BU1325, 5977, Unit 3 T3 Power Transformer BU1325, 5978, Transformer T4 (spare) BU1325, 5979, Transformer T5 BU1325, 5980, Transformer T6 BU1325, 5981, Transformer T7 BU1325, 5982, Transformer T8 BU1325, 5983, Transformer T9 BU1325, 5984, Transformer T10 BU1325, 6726, Unit 1 Service Power System, UST-1 Transformer BU1325, 8156, Unit 2 Service Power System, UST-2 Transformer BU1325, 8716, Unit 3, Unit Service Power System, UST-3 Transformer BU1325, 6727. Common, Stage 1, Station Service Power. SST-12 Trans BU1325, 5989, Common, Stage 2, Station Service Power, SST-34 Trans BU 1296, 271311, RT1, Unit 1 Rectifying Transformer BU 1296, 271324, RT2, Unit 2 Rectifying Transformer BU 1296, 271680, RT3, Unit 3 Rectifying Transformer

There are transformers both within the Holyrood plant managed by the plant (the unit rectifying transformers) and outside managed by the Transmission arm of Hydro. The requirements for the transformers vary depending on their role, but most if not, all will be required. The station has a spare Power Transformer on site. It is from before the Unit 1 and 2 upgrade and provides some measure of reliability.

Main Power Transformers	**T1** **Unit 1**	**T2** **Unit 2**	**T3** **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	???
Synchronous Condensing End Date	Dec 2043	Dec 2043	Dec 2043
Last Major Overhaul/Inspection	See Condition Assessment		


Figure 11-1 Unit 1 T1


Figure 11-2 Unit 2 T2


Figure 11-3 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 1978. 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%.

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.

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%.

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 115/152/190 MVA, Delta-Wye, 230kV:16kV, oil cooled.

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.

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%.

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%.

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.

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%. This transformer is out of service.

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.

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.

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. There was a condensation issue for this transformer.

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%.

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%. There was an issue of overcurrent trip for this transformer.

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%.

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. This transformer was replaced in the year of 2016.

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. This transformer was replaced in the year of 2016.

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. This transformer has a spare on site, there is no plan for replacement.

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.
- Annual oil sampling.
- Power Transformers have continuous gas/oil mounts.

Transformer Insulating Oil Test Results vs. IEEE Recommendations and Standards are given for each Section, with reference to the following:

Hydro (through the Transmission portion of the company) maintains a significant and regularly scheduled transformer maintenance and inspection program. Regular PM Work has been performed, but no data was available and documented during site visits. More testing and monitoring of equipment is being done for analyses of trends.

TRANSFORMER	FAILURE(S) (since 2010 report)	UPGRADES & REFURBISHMENTS (YEAR) (since 2010 report)	COMMENTS
T1	None	None	Oil DGA sampling interval is 1 year
T2	None	Gas detector relay replaced (2011) Both pressure relief devices replaced (2017)	Oil DGA sampling interval is 1 year

TRANSFORMER	FAILURE(S) (since 2010 report)	UPGRADES & REFURBISHMENTS (YEAR) (since 2010 report)	COMMENTS
T3	None	Oil level relay replaced (2010) Oil level relay replaced (2014) Winding temperature relay replaced (2014) Oil temperature relay replaced (2014) Gas detector relay replaced (2014) Winding temperature relay replaced (2016) Oil temperature relay replaced (2016) Hot oil rinse (2016) Oil replaced (2016) Coolers replaced w/ used coolers (2016)	Oil DGA sampling interval is 1 year
T4	None	None	Oil DGA sampling interval is 1 year
T4 Spare	None	None	PM last completed in 2016 Oil DGA sampling interval is 1 year
T5	Tap changer (2015)	Tap changer repaired (2015) X2 bushing replaced (2015) Winding temperature relay replaced (2015) HV surge arresters replaced (2015) Oil temperature relay replaced (2017)	Oil DGA sampling interval is 1 year
T6	None	Radiators replaced (2012) HV surge arresters replaced (2012) LV surge arresters replaced (2012) Oil level relay replaced (2014) Gas detector relay replaced (2015) Tap changer pressure relief device replaced (2015) Oil level relay replaced (2015) Tap changer oil level relay replaced (2015) Winding temperature relay replaced (2015)	Oil DGA sampling interval is 6 months
T7	None	Radiators replaced (2014) Oil level relay replaced (2015) Tap changer oil level relay replaced (2015) HV surge arresters replaced (2015) Winding temperature relay replaced (2017)	Oil DGA sampling interval is 6 months
T8	None	Replaced w/ new (2015)	Oil DGA sampling interval is 1 year
T9	None	Gas detector relay replaced (2014) Oil level relay replaced (2014) Winding temperature relay replaced (2014) Oil level relay replaced (2015) Oil temperature relay replaced (2016)	Oil DGA sampling interval is 1 year

TRANSFORMER	FAILURE(S) (since 2010 report)	UPGRADES & REFURBISHMENTS (YEAR) (since 2010 report)	COMMENTS
T10	None	Fault pressure relay replaced (2010) Winding temperature relay replaced (2016)	Oil DGA sampling interval is 3 months
SST1-2	None	Oil level relay replaced (2014) Winding temperature relay replaced (2014) Oil temperature relay replaced (2014) Oil level relay replaced (2015) Winding temperature relay replaced (2017) Oil temperature relay replaced (2017) Surge arresters replaced (2017)	Oil DGA sampling interval is 1 year
SST3-4	None	Neutral ground resistor replaced (2014)	Oil DGA sampling interval is 1 year
UST-1	None	Winding temperature relay replaced (2012)	Oil DGA sampling interval is 1 year
UST-2	None	Oil level relay replaced (2014) Winding temperature relay replaced (2014) Oil temperature relay replaced (2014) Oil level relay replaced (2015) Winding temperature relay replaced (2015)	Oil DGA sampling interval is 1 year
UST-3	Tap changer (2015)	Gas detector relay replaced (2014) Oil level relay replaced (2014) Winding temperature relay replaced (2014) Tap changer bypassed (2015)	Oil DGA sampling interval is 6 months

11.1.2.3 Condition Assessment

The condition assessment of all of the components is outside of the scope of this current update. Overall the various transformer equipment is in reasonably good shape for their age. More continuous monitoring of conditions such as gas in oil provides better trending of changes in condition.

Transformers T5, T6, T9, and UST-1 and UST-2 and SST-12 were indicated in 2010/11 to likely require refurbishment/replacement around 2016-2017.

- T5 is between Buses 7 and 11, providing 69 kV, with T10 (good condition) to Station Board SB12 through SST12
- T6 is between Bus 15 and Bus 8 supplying power to Whitborne (also T7 and T8 -. Bot in better condition)
- T9 is from old GT to SB12 – GT is out of service
- UST-1 between generator #1 and 4160 kV Unit Board UB1 – may be OK to Mar 2021
- UST-2 between generator #2 and 4160 kV Unit Board UB2 – may be OK to Mar 2021
- SSTT12 between Bus 2 and SB12 Common Stage 1 station services

Older equipment required for use past March 2023 may need to be replaced or refurbished sometime in 2023 to 2030. The timing of it will be determined through the PM programs in place.

11.1.2.4 Actions

The 2010/11 C.A and 2017 update report indicated that actions involved Dissolved Gas Analysis and Oil Quality tests/analysis. This and trend analysis are recommended to continue along with implementation of continuous gas in oil monitors. Based on this, transformers will be replaced or refurbished as part of an overall TRO Transformer Upgrade project between 2023 through 2030. No details are provided herein but can be obtained through TRO Asset Managers in Bishop's Falls.

11.1.2.5 Risk Assessment

The 2010/11 C.A and 2017 update report indicated that all transformers were medium risk due to back-ups and limited impacts. This has essentially not changed, although some upgrades and testing have been done.

More detailed Risk Assessment associated with these pieces of equipment are outside of the scope of this update.

11.1.2.6 Life Cycle Curve and Remaining Life

Older equipment required for use past March 2023 may need to be replaced or refurbished sometime in 2020 to 2030. The timing of will be determined through the PM programs in place. Newer items replaced since 2011 as part of a Transformer replacement/Upgrade project would be in good condition and will last, with regular PM and maintenance, to at least 2043.

11.1.2.7 Level II Inspections

No specific Level II inspections are within the scope of this update. Ongoing inspections are undertaken by TRO and Holyrood GS as part of their Asset Management and PM's.

11.1.2.8 Capital Projects

Development of a Capital Program is outside scope of this update. It was proposed that such a plan be developed in 2020. For the purposes of this update, it is recommended that the internal plan be updated and implemented. No details are provided herein, but likely for equipment required by the system beyond the March 2023 end of Holyrood generation life can be obtained through TRO Asset Managers in Bishop's Falls.

11.1.3 Assets 6860 and 8730 – Common Electrical and Control Assets

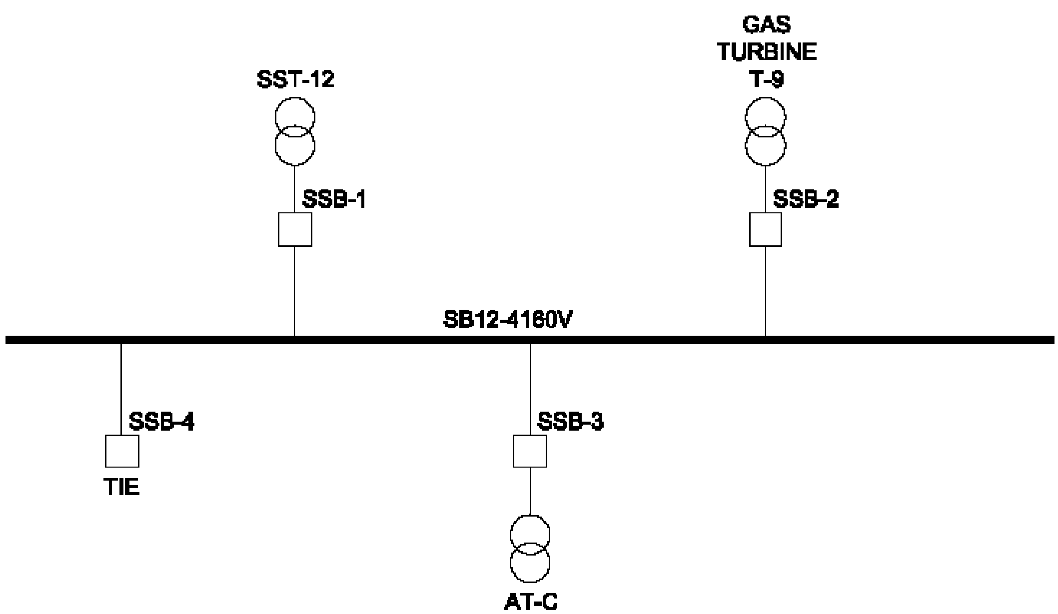
The requirements for the systems associated with the generator for Holyrood are as follows:

Unit #:	**Common**

Asset Class #	BU 1297 - Assets Commons
SCI & System:	7199 - HRD Common Systems
Components:	6904. Common, Computers Foxboro 7189. Common, Switchgear 4160V/600V (SB12) 7190. Common, Diesel Bus, DB12 7192. Power Centre C (SAB12, Diesel Bus DB12) 7197. Common, Stage 1, 129VDC Supply System UNITS 1 to 3 Common, Control Cables Common, Power Cables Common 600V Metric Plugs

11.1.3.1 Description (No major change since 2010/2011 C.A and 2017 update Report)

Figure 11-4 SB12 Switchgear



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 for Unit Board SB12 Protection are available, dated 2007. Results were 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.

No data was identified that this had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

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.

No data was identified that this had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

Asset 7190. Common, Diesel Bus, DB12

Diesel Bus DB12 is part 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.

No data was identified that this had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

Asset 7192. Power Centre C (SAB12, Diesel Bus DB12)

The last PM performed as of 2010/11 report was between 1992 and 1997. Breakers were sent away to an external company for maintenance, who changed the protection relay on each breaker. The Stantec Engineering Report – MCC Assessments, Section 1.0 concludes that all 600V switchgear is applied within their ratings.

No data was identified that this had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

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.
No data was identified that this had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

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 Planned Maintenance was carried out on Power Cables, approximately, every 10 years. Since 1995 no PM has been identified as having been done or records available. Visual inspection indicates some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Modifications, over the last 40 years, has resulted in cables, power and control, being "placed" into trays that have been convenient in the routings associated with the new installations.

11.1.3.3 Condition Assessment

The condition assessment of these systems was not addressed within the scope of the update.

Near term and/or High-Risk issues in 2010/11 study were:

- Asset 7199/7192. Power Centre C (Safety – Loss Pumphouse Stage 2, MCC C6; 1 unit; damage) - at end of life by 2015
- Asset 8730/8746 CW Pumphouse MCC CWP-34 – Loss Pumphouse Stage 2, MCC C6; 1 unit; damage) - at end of life by 2015.

No data was identified that these had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report.

Several other assets had 5 to 10-year remaining lives in 2010/11 Condition Assessment review. No data was identified that these had been refurbished/replaced/overhauled since 2010/11 Condition Assessment report. If not, their Condition should be evaluated.

11.1.3.4 Actions

Based on the limited review of the 2010/11 Condition Assessment and 2017 update Report, the following Actions are recommended for Common Electrical and Control Assets.

- Verify condition/status of Assets in 2010/11 report having 2 to 10-year remaining life

11.1.3.5 Risk Assessment

Based on the limited review of the 2010/11 Condition Assessment, the following Risk Assessment comments associated with the system may apply. In most cases system redundancy and spare part availability limit the scope of the risks to partial or full loss for a short duration of one unit. Based on experience to date and expected results from ongoing inspections/maintenance/PM's most 2010/11 items would remain as "Low to Medium" Risk.

11.1.3.6 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, it is expected that the remaining life (RL) of most of the Common Electrical and Control Assets exceeds the end date for generation of 2023, but not the desired life (DL) which is the end date for synchronous condensing of 2043.

Older switchgear such as breakers or motor control centres that had 2 to 5 year remaining life should be assessed for need to be replaced (some possibly refurbished) as soon as possible, or risk increasing rates of failure leading to partial unit generation capacity loss for moderate periods of time.

11.1.3.7 Level II Inspection Requirements

Given the Risk and Life information from 2010/11 C.A and 2017 update report, no Level II analyses are likely required, but Older switchgear such as breakers or motor control centres that had 2 to 5 year remaining life should be inspected and assessed as soon as possible.

11.1.3.8 Capital Projects

Some capital enhancements for elements of the breaker and motor control centres are likely to be required, particularly those that had a 2 to 5 year expected remaining life in 2010/11 and particularly if they are required for synchronous condensing option, or for reliable station service supply.
No data was identified during site visits and discussions as to what had been refurbished/replaced/overhauled since the 2010/11 Condition Assessment report.

11.1.4 Asset 272255 – Buildings and Building M and E System

Unit #:	COMMON
Asset Class #	BU 1297 - Assets Common
SCI & System:	7255 - HRD Buildings & Site
Sub-Systems:	272255 - HRD Buildings
Components:	7283 - Main Powerhouse 7285 - HRD Stage 1 Pumphouse 7286 - HRD Stage 2 Pumphouse 7284 - HRD Training Centre 7287 - HRD Guardhouse 7288 - HRD H2 and CO2 Storage Building 7302 - HRD Shawmont building

	7303 ‐ HRD Main Warehouse 7307 ‐ HRD Gas Turbine Building XXXX – Six 2 MW Diesel Generators (Emergency/Black Start) XXXX – One Siemens 120 MW Simple Cycle Gas Turbine Generator

11.1.4.1 Description

Asset 7283 - Main Powerhouse

Upgrades to siding and roofing, addressing asbestos in siding and roof repairs, have been completed in 2017.

Asset 7307 – HRD Gas Turbine Building

The Gas Turbine Building at Holyrood Thermal Generation Station (HTGS) remains, but the gas turbine is no longer in-service.

Asset XXXX – Six 2 MW Diesel Generators (Emergency/Black Start)

Six 2 MW simple cycle diesel engine generators (mobile trailer mounted, low stack) were installed to provide black start capability to HRS TGS. Taller stacks were added for point of impingement reasons in 2018

Asset XXXX – One Siemens 120 MW Simple Cycle Gas Turbine Generator

One 120 MW simple cycle gas turbine generator using water injection for NOx control, along with associated fuelling and connection facilities was added to site – No included in scope of this Update.

11.1.4.2 History (No major change since 2010/11 C.A and 2017 update Report)

Fire protection and alarm tie-ins were completed in out buildings in 2105

11.1.4.3 Inspection and Repair History

Asset 7283 - Main Powerhouse

Roofs & Siding – Upgrades to siding and roofing, addressing asbestos in siding and roof repairs, have been completed per management plan.

HVAC - 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 shape and inefficient. While maintained regularly, primarily on an as-required basis, it is clear that the system's condition is not consistent with what will be required of it when the main boilers are not in-service when the units are put into synchronous condensing operation.

Elevators - The two elevators: The Boiler house elevator and the Administration Office elevator have been inspected and refurbished and subsequently inspected and maintained regularly as required.

Vestibules - In 2018 Vestibule improvements were made to Door #5 and Electrical and Instrumentation shop.

Cranes – In 2018 crane inspection were carried out (2018 Crane inspections – 25 and 170 ton cranes) on the plant 25 and 170 ton cranes, and both cranes passed.

Asset 7285 – HRD Stage 1 Pumphouse

No inspection specific to the pumphouse was identified or reviewed and no interviews indicated any recent inspection information. A visual walkthrough of both pumphouse buildings was performed to gauge the existing condition of the buildings.

Structural - The structural steel in the building appears 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 the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. They seem in good condition, although experiencing some corrosion internally and externally consistent with a seaside environment

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. There does not appear to be any major issues 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 -

No inspection specific to the pumphouse was identified or reviewed and no interviews indicated any recent inspection information. A visual walkthrough of both pumphouse buildings was performed to gauge the existing condition of the buildings.

Structural - The structural steel in the building appears 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 the powerhouse upgrade between 1990 and 2000. Visually, the metal roofs show some signs of corrosion and wear due to the marine environment. They seem in good condition, although experiencing some corrosion internally and externally consistent with a seaside environment

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*e been modified they have undergone the standard 120+% waterbag test to ensure they are functioning. There does not appear to be any major issues 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 7284 – HRD Training Centre

No inspection specific to the building were identified or reviewed and no interviews indicated any recent inspection information. A visual walkthrough was performed to gauge the existing condition.

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

A new building was implemented after the 2010/2011 study. No inspection specific to the building were identified or reviewed and no interviews indicated any recent inspection information.

Asset 7288 – HRD H2 and CO2 Storage Building

No inspection specific to the building were identified or reviewed and no interviews indicated any recent inspection information. A visual walkthrough was performed to gauge the existing condition.

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

No inspection specific to the building were identified or reviewed and no interviews indicated any recent inspection information.

Asset 7307 – HRD Gas Turbine Building

No longer in service. No inspections.

Asset XXXX – Six 2 MW Diesel Generators (Emergency/Black Start)

No inspection specific to the mobile units was identified or reviewed and no interviews indicated any recent inspection information. An external visual walkthrough was performed to gauge the existing condition.

Asset XXXX – One Siemens 120 MW Simple Cycle Gas Turbine Generator

Not in scope of Update.

There was an inspection and installation of improved HGTS out building fire detection systems in 2019 for the Training Center, the Shawmont building, and the Pipe Shop. (HTGS Out Buildings Fire Detection - Project Binder 2019).

11.1.4.4 Condition Assessment

The buildings identified are generally in reasonable condition for a March 2021 end of generation service life.

The main powerhouse needs some form of building heating system if it continues as a synchronous generation source to 2043 – requiring a heating source and possibly some segregation of facilities to minimize heating requirements and costs. For cold standby/emergency mode, auxiliary steam supply using Unit 3 boiler as an auxiliary boiler could be one option for building heating as well.

Stage 2 pumphouse (or Stage 1) will be required for synchronous condenser operation to 2043. With normal PM maintenance the requirement is expected to be achievable with minimum effort in near term.

The six 2 MW diesel generator mobile units are suitable for continued emergency service for 20 years, Ground level emission levels required additional stack heights installed in 2018.Actions

Given the actions taken since 2010/11 report and based on its overall condition assessment and risk assessment, no major actions beyond normal inspections, maintenance, and PM work is recommended to meet the March 2023 end of life date, and likely to cold standby/emergency mode to 2027+..

For facilities required beyond March 2023:

- a further Condition Assessment for applicable systems is recommended for 2022.
- The Main Powerhouse will require a new building heating system (possibly partitioned powerhouse) and should consider Unit 3 boiler as an auxiliary steam source during cold standby/emergency mode as an option.

11.1.4.5 Risk Assessment

The 2010/11 Condition Assessment Report showed “High” risk ratings for the Main Powerhouse Elevator (Safety) and for Fire Protection System/Diesel Fire pump (safety). Both were addressed and now would be “Low Risk”.

Other 2010/11 identified risks are expected to remain in “Low to Medium” range, both from a technological perspective and a safety perspective, if normal inspection, maintenance, and PM work are followed.

11.1.4.6 Life Cycle Curve and Remaining Life

Given the investments and experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve for the Buildings would see all "yellowed" risk area/boxes shift beyond the 2023 period.

11.1.4.7 Level II Inspection Requirements

Given the investments and experience since the 2010/11 Condition Assessment and 2017 update report, no Level II inspections are required, premised on that the normal inspection, maintenance and PM programs are maintained.

11.1.4.8 Capital Projects

No significant capital enhancements for the system are recommended to maintain a March 2023 end of generator life, provided regular maintenance repairs and minor capital replacements found during inspections are undertaken.

For facilities required for Synchronous Condenser operation beyond 2023 to as late as 2043:

- Revised Condition Assessment Level 1 in 2022`
- Main Powerhouse building heating (and possible building segregation) in 2021.

11.1.5 Asset 7206 – Hydrogen and Carbon Dioxide Supply Systems

The requirements for the switchgear and switchyards for Holyrood 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 7237 Carbon Dioxide Storage & Supply

11.1.5.1 Description

The scope examined includes only the hydrogen and carbon dioxide storage and delivery elements, not the building itself.

The hydrogen and carbon dioxide are supplied from a gas storage steel building to the east of the powerhouse. IN 2010/11 both gases as well as nitrogen are stored in high pressure cylinder packs connected to the lines that go underground to the plant and from there to the individual units.
One issue with the hydrogen was that there was no other major Newfoundland user and hence no Newfoundland based supplier. It must be shipped from off-island. This led to the installation of a site-based hydrogen production facility. Issues with the system led to the installation of a bulk hydrogen storage system.

Figure 11-5 Hydrogen Lines in Powerhouse

Figure 11-6 Hydrogen Lines into Powerhouse

11.1.5.2 History

The issues with hydrogen availability on the island led to the installation of a site based hydrogen production facility. Issues with that system led to the installation of a bulk hydrogen storage system.

11.1.5.3 - 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.

11.1.5.4 Condition Assessment

No detailed condition assessment of the systems was undertaken. The systems should be reliable to the March 2023 end of generation date and beyond, provided regular inspection, maintenance, and PM work is continued.

11.1.5.5 Actions

No Actions for the systems beyond regular inspection, maintenance, and PM work is required for reliable operation to the March 2023 end of generation date and beyond. More detailed inspections and systems analysis may be warranted in 2021.

11.1.5.6 Risk Assessment

The 2010/11 Risk Assessment associated with the systems had no "High" risk items. The same applies in 2017. Hydrogen systems at individual generator units may however require more detailed investigation in 2020, both from a technological perspective and a safety perspective.

11.1.5.7 Life Cycle Curve and Remaining Life

Given the investments and experience since the 2010/11 Condition Assessment and 2017 update report, the primary change to the Life Cycle Curve for the gas systems would see all "yellowed" risk area/boxes shift beyond the 2020 period.

11.1.5.8 Level II Inspection Requirements

Given the investments and experience since the 2010/11 Condition Assessment report, no Level II inspections are required for the March 2023 end of generation service, premised on that the normal inspection, maintenance and PM programs are maintained. Additional more detailed inspections may be warranted in 2022 associated with the 2043 date for synchronous condensing.

11.1.5.9 Capital Projects

No significant capital enhancements for the system are recommended to maintain a March 2023 end of generator life, provided regular maintenance repairs and minor capital replacements found during inspections are undertaken.

The capital requirements for facilities required for Synchronous Condenser operation beyond 2023 would likely occur in the 2022 timeframe and should be identified as part of a 2020 inspection assessment.

11.1.6 Asset 7231 – Compressed Air

Unit #:	1-3
Asset Class #	BU 1297 - Assets Commons
SCI & System:	7199 HRD Common Systems
Sub-Systems:	7205 Compressed Air Systems
Components:	7231 Compressors 7234 Compressed Air Dryers Systems 7235 Compressed Air Receivers

11.1.6.1 Description (No major change since 2010/11 C.A and 2017 update Report)

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.

11.1.6.2 History (No major change since 2010/11 C.A and 2017 update Report)

Compressor #1 was replaced in 2014/15 and compressor #2 Ingersoll Rand Sierra HH200W in 2016.

11.1.6.3 Inspection and Repair History

The service air pressure vessels and instrument air pressure vessels are inspected annually in accordance with government regulations. The instrument air filtering and drying systems also receive annual maintenance No indication of any significant degradation or maintenance/regulatory issues during annual inspections were identified.

11.1.6.4 Condition Assessment

The compressed air system are considered in good enough condition to be able to achieve generation end of life in March 2023.

For Stage 2 service beyond 2023 or potentially 2043, life considerations would suggest that the instrument air receiver systems and the service air receiver systems require refurbishment or replacement.

11.1.6.5 Actions

Based on the condition assessment and end of service generation life of March 2023, no further actions beyond regular inspections, maintenance, and PM's are recommended.

For Stage 2 service beyond 2023, replace one of instrument air receiver systems and one of the service air receiver systems.

11.1.6.6 Risk Assessment

The risk assessment associated with the compressed air system, both from a technological perspective and a safety perspective, is considered low for 2023, and higher for beyond 2023 to 2043 period.

11.1.6.7 Life Cycle Curve and Remaining Life

Given the experience and changes since the 2010/11 Condition Assessment and 2017 Update Report, all elements are considered to exceed the March 2022 end of generation life. For the 2023 to 2043 Unit 3 synchronous condensing life, some refurbishment and/or replacement is likely warranted/required in 2023 to 2025.

11.1.6.1 Level II Inspection Requirements

No Level II inspections are required for the March 2023 end of generation service, premised on that the normal inspection, maintenance and PM programs are maintained.

11.1.6.2 Capital Projects

Capital replacement or major refurbishment of one of the two instrument air receiver systems and one of the two service air receiver systems in 2023-2025 are suggested.

11.2 Common Systems - Lower Priority Systems

11.2.1 Assets 7209 and 7204 – Fuel Systems (Light and Heavy Oil)

- High for 2019 C.A

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 (No major change since 2010/11 C.A and 2017 update Report)

Heavy Oil System

The original #6 residual oil was a high sulphur (2.5%S+), high vanadium, "dirty" fuel. Given the boiler design, particularly the back-end economizer and air preheater, as well as the reheater, the boiler frequently was shut down during the operational season for major boiler cleaning. The effects of that fuel have had an impact of boiler heating sections and tubes even as recent as 2016 (even though last used in 2007). In 2007 a switch was made to a 0.7%S, lower vanadium fuel that saw immediate improvements in terms of operation reliability, but some of the damage continued "under the surface".

Unfortunately, in 2015, a fuel supplier switch resulted in a different kind of fuel problem that saw significant erosion due to silica and alumina concentrations and from fuel separation. This resulted in severe deposition in tanks and erosion in filters, pumps, heaters and burners, resulting in several millions of $ of equipment replacements.

The main oil tanks each has a functioning steam suction heater for temperature control of the oil discharge, but their two immersion platform heaters in the tank itself are non-functional. There is no internal mixing or stirring or recycle. Steam from the auxiliary steam system provides the thermal input. Condensate is discharge via steam traps to drains. A 16" radial pipe to the 18" main supply header takes the oil from the tank farm by gravity flow to the Day Tank.

The fuel specification and purchases were improved since 2015, and fuel system maintenance and reliability has been restored to expected levels.

11.2.1.2 History - Inspection and Repair History

The tank refurbishment program in 2010/11 was intended 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

In 2017 an inspection of the 6" auxiliary steam piping to the main fuel oil tanks was undertaken (Team Industrial Auxiliary Steam Piping to Tank Farm LRUT Report (October 2017)) by TEAM Industrial Services. The inspection included guide wave screening of the pipeline and direct visual inspection of collar attachment points (and compression wave ultrasonic examination of pipe thickness at those points).

Thirty-seven locations were accessed, by stripping insulation and mechanical cleaning of surface. Some limits on test lengths were noted by welds and under insulation corrosion.

- corrosion under insulation in most areas; corrosion pitting worse than at collar attachments
- rust bloom and pitting at collar attachment points, worst pitting in expansion loop between tank 3 and 4 (up to 0.040")
- general external corrosion, worst in tank farm area
- Expansion joint between power plant and tank farm found severely corroded
- Radiography recommended at lower elbow and piping to the east.

The corrosion under insulation was considered to be caused by open insulation cladding allowing water ingress into line surface. The piping of the steam line does not appear to heat enough to dry insulation out. Insulation was wet and damp at each collar location.

Excerpt from the inspection report below.

Most areas inspected with guided wave indicate that corrosion under insulation is present. Data indicated that multiple areas of corrosion pitting were observed throughout the test lengths inspected. Visual inspections indicated rust bloom and pitting at each collar attachment point. General external corrosion was noted along the entire pipeline with the worst cases being up in the tank farm. Data collected from TL-9 through TL-29 illustrate this condition. The worst pitting noted was found in the expansion loop between tank 3 and 4. Here external corrosion pitting measured up to .040". Guided wave data also indicated corrosion pitting worse than at the collar attachment point. TL-7 noted on the expansion joint between the power plant and the tank farm is excluded to this rule. Piping noted at TL-7 expansion loop was found to be severely corroded. Due to the corrosion, radiography is recommended at the lower elbow and the piping to the east.

Pit depth of .030"

General corrosion noted prior to pre-cleaning

Guide wave screening was inaccessible to some areas:

- Condensation pots, not inspected
- Wall penetration at north end of tank lot (TL8 to TL9)
- The two 4" take-offs to each tank
- All tees and branches and elbows in pipeline

Piping from the main line to each tank was inspected. The original paint coat was located on tanks 1 to 3 and had failed allowing rust bloom and pitting. Tank 4 had been recoated and the paint coat was in good condition, arresting any further corrosion.

Tables from the Hatch 2017 report below.

Location	Wall Thickness (Paint thickness estimated to increase each thickness reading by .015 - .020")				Datum Description	Datum to Tool (ft)	Diagnostic Test Length (ft)		Anomalies Identified		Comments
	12	3	6	9			Forward	Backward	Cat	Priority	
TL-1 Power Plant Road Crossing	.28	.297	.3	.300	Weld at bottom elbow tank farm side of main road crossing	9	31	-11	3	Low	Minor corrosion noted at pipe supports
TL-2 Piping from Road –TK1	.288	.288	.270	.300	Weld at top elbow tank farm side of main road crossing	30	30	-67	-	-	No corrosion noted
TL-3 Piping from Road –TK1	.28	.288	.287	.288	Collar attachment location for test location #2	110	55	-40	-	-	No corrosion noted
TL-4 Piping from Road –TK1	.280	.278	.275	.280	Expansion joint	22	22	-58	2	Low	Minor CUI (Pitting .005" - .010") noted at the collar location. Anomalies noted exhibit corrosion slightly worse .
TL-5 Piping from Road –TK1	,280	.285	.282	.290	Elbow at bottom of hill near first expansion loop	-60	139	-60	-	-	No corrosion noted
TL-6 Piping from Road –TK1	.288	.287	.298	.290	Elbow at hill near expansion loop	+12	12	-51	4	Medium and low	1 medium priority anomaly noted along with 3 other low priority anomalies. Internal corrosion noted at the collar location as well as slight CUI. Pitting ,005" - .010"
TL-7 First Expansion Loop	.280	.275	.277	.267	Elbow at lower end of expansion loop	+4	5	-22	7	Medium and low	Heavy scale and CUI noted at the collar location. Pitting depths of ..020" to .030" were noted. Piping forwards of the collar exhibits heavy corrosion near the elbow. Radiography recommended on the fitting and the piping upstream.
TL-8 Between First Expansion Loop and TK#1	.312	.300	.285	.295	Weld on elbow turning west on first expansion loop	21	21	-21	5	Medium and low	Moderate CUI located at the collar location. Minor internal also noted. Pitting depths of .020" - .030" were noted. An attempt was made at analysis of the wall penetration in the backward direction. The resultant response was inconclusive due to the geometry of the centering device installed.
TL-9 Upstream of TK#1 Tee	.312	.300	.275	.295	Tee to Tank #1	-7	45	-20	6	Medium and low	Moderate to heavy CUI noted at the collar location. Pitting depths of .020" to .030" were noted. Slight internal pitting also noted.
TL-10 Tk#1 take off to exp. Loop	.280	.282	.294	.280	Lower elbow west end of TK#1 lot	+6	6	-32	5	Medium and low	Moderate to heavy CUI noted at the collar location. Pitting depths of .020" to .030" were noted. Slight internal pitting also noted. U-bolts attached to the line exhibit corrosion and wall loss. Spot Radiography recommended
TL-11 TK#1 Expansion lop	.267	.275	.278	.270	East elbow of #1 tank expansion loop	+4	15	12	4	Low	Minor CUI (Pitting .005" to .010") noted at the collar location. Corrosion anomalies noted during inspection are expected to have similar wall losses
TL-12 Tank #1 Inlets	.287	.313	.282	.296	Flange at east end of line	-12	41	-12	3	Low	Minor CUI (Pitting .005" to .010") noted at the collar location. Corrosion anomalies noted during inspection are expected to have similar wall losses. Most corrosion is noted at U-Bolts.
TL-13 Piping between #1 and #2 TK	.265	.260	.255	.267	45 degree elbow west side of #1 tank	+45	45	-40	5	Medium and low	Moderate CUI (Pitting .020" to .030") noted at the collar location. Corrosion anomalies noted during inspection are expected to have similar wall losses. A vent in the forward direction exhibits higher than normal horizontal flexural signals. Radiography recommended

loop between #1 and #2 TK north side										
TL-15 Expansion loop between #1 and #2 TK east side	.275	.265	.280	.278	Elbow on north side of expansion loop	+5	30	-30	5	Medium and low	Heavy scale and CUI noted at the collar location. Spot radiography recommended. Pitting depths of .020" to .030" noted. Anomalies noted indicate wall losses greater than at the collar location.
TL-16 Expansion loop to Tank #2	.255	.265	.278	.280	Elbow South side of Expansion loop	+4	5	-41	4	Medium and low	Heavy scale and CUI noted at the collar location. Spot radiography recommended. Pitting depths of .020" to .030" noted. . Anomalies noted indicate wall losses greater than at the collar location.
TL-17 Tank #2	.288	.292	.304	.284	Elbow at bottom of TK# 2 take off	+6.5	6	-48	4	Low	Minor rust bloom noted at the collar location. Anomalies noted at low in amplitude and at the U-bolt attachments.
TL-18 Tank #2 Expansion loop	.306	.282	.283	.302	Elbow north east corner of TK#2 expansion loop	-9.5	30	-10	4	Low	Minor rust bloom noted at the collar location. Anomalies noted at low in amplitude and at the U-bolt attachments.
TL-19 Tank #2 inlets	.268	.271	.289	.283	Elbow at north west corner of expansion loop	24.5	15	-52	5	Medium and low	All U-bolt attachments indicate touch point corrosion. Recommended spot radiography of these to validate abnormal signals. The u-bolt attachment directly forward of the collar absorbed much of the sound energy and limited the test length. This is caused by extreme intimate contact with the pipe or corrosion. Further inspection of this feature is recommended.
TL-20 piping between Tk #2 and 3	.295	.284	.276	.288	Weld on valve South of Tk#2 Tee	22	22	-32	4	Low	Minor to Moderate CUI noted at the collar location. General corrosion of .005" to .010" noted.
TL-21 North	.284	.309	.289	.291	Tee to tank #3	-130	30	-35	7	Medium and	This location was added north of TL-21 due to limited shot range. Shot ranges this short indicate
Piping between TK#2 and TK#3										low	CUI and scale throughout. Minor to moderate CUI noted at the collar location. Pitting depths of .010" to .020" deep were noted. Anomalies noted are general corrosion slightly worse than the collar location.
TL-21 Piping between TK#2 and TK#3	.304	.271	.308	.268	Tee to tank #3	-74	22	-15	5	Low	Minor to Moderate CUI noted at the collar location. General corrosion of .005" to .010" noted.
TL-22 Tank #3 take off	.287	.300	.302	.277	Elbow east end of TK#3 expansion loop.	-6.5	26	-31	7	Medium to low	Moderate CUI noted at the collar location. Pitting .020" to .030" was noted. U-Bolt attachment points indicate touch point corrosion. Further inspections of these areas are recommended.
TL-23 Tank # 3 Expansion Loop	.278	.292	.276	.289	Weld on valve east side of expansion loop	-2	35	-2	8	Low	Minor to moderate CUI noted at the collar location. Pitting depths of .010" to .020" measured.
TL-24 Tank #3 inlets	.257	.287	.302	.277	Elbow on north east corner of expansion loop	35	30	-50	8	Low	Minor to moderate CUI noted at the collar location. Pitting depths of .010" to .020" measured. Corrosion anomalies noted in the scan are mostly located at u-bolt attachments.
TL-25 Piping between #3 and 4	.260	.287	.302	.290	Weld on TK# 3 Take off	63	63	-54	20	Low	Moderate to severe CUI noted at the collar location and indicated in the inspection. Multiple areas indicative of CUI pitting was noted throughout the scan. Corrosion pitting at the collar was found to be .030" to .040"
TL-25 South Piping between #3 and 4	.294	.278	.264	.247	Weld on elbow on north side of expansion loop	-23	43	-23	6	Medium	This shot was added due to limited shot range in TL-25 / 26. Moderate to severe CUI was noted at the collar location and is indicated through the scan. Medium priority wall loss anomalies were noted throughout.
TL-26 Piping	.260	.287	.302	.290	Weld on elbow of expansion	14	20	-30	7	Medium and low	Severe CUI was noted at the collar location. Pit depths up to .040" were noted. Guided wave data is indicative of the same condition. Recommend

between #3 and 4					loop southwest of TK#3						spot radiography to verify some of the corrosion noted.
TL-27 Piping between TK # 3 and 4	.324	.320	.310	.304	Weld on south east corner of expansion loop southwest of TK # 3	18	20	-30	4	Medium and low	Tightly adhered scale and pitting prevented adequate coupling for true UT thickness readings. Minor to moderate CUI noted with pitting of .040" to .050" was noted. Guided wave data indicates that similar wall loss is expected in the backward direction. Forward, moderate to severe wall loss was noted.
TL-28 Piping between TK # 3 and 4	.284	.282	.283	.267	Weld on elbow south west corner of expansion loop south west of TK # 3	22	23	-30	4	Medium and low	Minor to moderate CUI was noted at the collar location. Areas of pitting of .010" to .020" were noted. Similar wall losses were noted in the guided wave inspection.
TL-29 Piping between TK # 3 and 4	.300	.297	.297	.304	Flange at south end of pipeline	-24	32	-24	7	Medium and low	Minor to moderate CUI was noted at the collar location. Pitted areas of .015 – 030" were noted.
TL-30 Tank # 4 take off	.315	.315	.312	.317	Elbow at bottom west end of take off	9	9	-33	3	Low	This section of piping appears to be re painted. Corrosion noted does appear to be from prior to the recoat.
TL-31 Tank #4 Expansion loop	.311	.312	.312	.304	Valve on east side of expansion loop	-4	40	-10	-	-	Very low amplitude signals noted from corrosion anomalies. The section inspected at this test location has also been recoated.
TL-32 Tank # 4 Inlets	.282	.299	.272	.278	Elbow on north west corner of TK4 expansion loop	18	28	-30	-	-	Very low amplitude signals noted from corrosion anomalies. The section inspected at this test location has also been recoated.
TL-32 Tank # 4 Inlets	.283	.284	.283	.294	Flange at east end of line	8	33	-12	1		Very low amplitude signals noted from corrosion anomalies. The section inspected at this test location has also been recoated.
TL-34 Clean out spool to road crossing by TL#1	.292	.284	.310	.287	Flange in trench to clean out spool	16	16	-32	3	Low	Minor CUI noted at the collar location. Guided wave data indicates similar wall losses throughout the inspected area.
TL-35 Clean out spool to power house	.298	.302	.317	.288	Flange in trench to clean out spool	-19	17	-18	3	Low	Minor CUI noted at the collar location. Guided wave data indicates similar wall losses throughout the inspected area.

The timing of API 653 inspections reporting had been:

- Tank #1 July 2016 (Tank 1 API 653 In-Service Inspection Report – Nalcor Tank #1 HRD, July 2016)
- Tank #2 Dec 2008 (Tank 2 API 653 Out-of-Service Inspection Report – Tank #2 HRD, Dec 2008)
- Tank #3 Nov 2003 (Tank 3 API 653 Out-of-Service Inspection Report – Tank #3 HRD, Dec 2008)
- Tank 3 API 653 Inspection June 2013

The timing of inspections associated with API 653 and regulatory requirements were planned to continue, however as of 2017 this had changed to allow for starting to retire tanks or deferring inspections (particularly internal out-of-service inspections beyond March 2021).

A great deal of upgrade work has been 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.

In 2017 Tank 1's condition was assessed (Tank 1 Hatch 2017 Condition Assessment):

- Chine condition (extension of floor outside tank) and caulking deteriorated badly – allowing water under bottom of tank and ringwall – accelerating bottom plate corrosion
- Ringwall had significant cracking, crumbling, and spalling
- Significant corrosion on roof plate, two holes
- New 2015 platform which was temporarily attached to roof plate using structural adhesive – begun to deteriorate and failing, needing more permanent solution
- Small coating spot damage on shell
- Tank 1 piping insulation and support deterioration
- Steam leak on outlet piping near Tank north side

In 2017 Tank 2's condition was assessed (Tank 2 Hatch 2017 Condition Assessment):

- Similar to Tank 1, deteriorating conditions
- Chine condition (extension of floor outside tank) and caulking deteriorated badly – allowing water under bottom of tank and ringwall – accelerating bottom plate corrosion
- Ringwall had significant cracking, crumbling, and spalling
- Significant corrosion on roof plate, one hole in area of inspection without fall protection
- Notable tank coating deterioration
- Tank 1 piping insulation and support deterioration
- Steam traps on south and west blowing onto shell and ringwall accelerating coating and ringwall breakdown

In 2017 Tank 3's condition was assessed (Tank 3 Hatch 2017 Condition Assessment):

- Better condition than Tanks 1 and 2
- Coating section on east, south, west sides damaged
- Chine caulking starting to crack at various locations
- Concrete ringwall cracks developing
- Steam traps on south and west blowing onto shell and ringwall accelerating coating and ringwall breakdown
- Tank 3 piping insulation and support deterioration, pipe support on south side failed and may have excessive loading on nozzle to tank

In 2017 Tank 4's condition was assessed (Tank 4 Hatch 2017 Condition Assessment):

- Multiple small sections of coating damage and large sections where may be shedding/delaminating on east, south, west sides
- Steam traps blowing onto shell and ringwall accelerating coating and ringwall breakdown
- Multiple areas around tank holding water
- Concrete ringwall cracked and crumbling
- Pipe support on NW side has concrete support pier deterioration – leaving gap between support plate and pier – accelerating by steam traps blowing onto it

Tank Deficiencies List - 2017 Holyrood Generating Station

Tank 1

No.	Location	Item Type	Deficiency	Original Observation Date	Comments	Recommended Repairs	Observation Date
1	**Compound**						
1.1	Compound	Operating Instruction	Drainage needs to be maintained to ensure no acceleration of the underside corrosion.	March 2006-SGE Acres Evaluation Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Perform additional Tank Farm inspections to ensure excess water is not building up around the tank.	Hatch - May 3, 2017
1.2	Compound	Repair	Repairs should be made to the compound so water that is standing will filter away from the tank and to a common sump area.	Dec. 2005-AITEC Out of Service Inspection Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Perform additional Tank Farm inspections to ensure excess water is not building up around the tank.	Hatch - May 3, 2017
1.3	Compound	Repair	Walkovers are constructed of lumber. These should be replaced by steel walkovers	Hatch - May 3, 2017	Current walkovers and platforms do not meet NFPA	Replace existing lumber walkovers with new galvanized steel walkovers	Hatch - May 3, 2017
2	**Floor**						
2.1	Tank Bottom	Repair	The calculated corrosion rate is 0.029". Based on this rate there was a total of 3 plates that had wall loss of 50% or greater which require repair or patching to give the tank floor a ten (10) year life span.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Based on previous corrosion rates the floor is overdue for replacement.	Hatch - May 3, 2017
2.2	Floor Plate	Replacement	Recommend the removal of the existing floor coating system and recoating the floor and lower 1 meter of the tank shell.	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Tank floor will need to be recoated with floor replacement	Hatch - May 3, 2017
2.4	Floor to Corner Weld	Repair	Repair 11 areas on the floor to corner weld at the bottom toe of the weld where there is pitting corrosion and inspect by magnetic particle.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by floor replacement	Hatch - May 3, 2017
2.5	Floor to Shell Weld	Repair	Repair 30 areas on the top toe of the corner weld that had linear indications and inspect by magnetic particle.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by floor replacement	Hatch - May 3, 2017
2.6	Tank Bottom	Repair	Install patch plates on 12 areas of the floor where there is underside corrosion, topside pitting and areas where plates were cut out for soil samples. Inspect by MPI and vacuum box. Repair or replace 3 plates which had wall loss of 50% or greater.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by floor replacement	Hatch - May 3, 2017
2.7	Tank Chine	Repair	There is no seal in some areas at the base to chine interface to the concrete pedestal; this condition should be mitigated. The bottom plate chine projection also displayed signs of minor corrosion concerns.	July 2016-Team In Service Inspection Report	This has not been addressed and has continued to deteriorate.	Installation of asphalt impregnated fiber board should be installed between chine and ringwall during floor replacement.	Hatch - May 3, 2017
3	**Roof**						
3.1	Roof Plate	Replacement	The roof plate needs to be replaced in 5 years due to unusual underside corrosion. Recommend replacement. (2005 AITEC report also recommended a maximum 5 year remaining life with replacement in this timeframe)	March 2006-SGE Acres Evaluation Report	This has not been addressed and has continued to deteriorate.	Based on previous corrosion rates the roof is overdue for replacement.	Hatch - May 3, 2017
3.2	Roof Rafters	Inspection	Rafters need to be checked to determine cause of sweep. Further inspection should be carried out during roof plate replacement. There is a concern for the amount of deflection.	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Issues encountered with rafters most likely point to rafters being undersized/corroded. Rafters are overdue for replacement	Hatch - May 3, 2017
3.3	Tank roof	Inspection	Cut out 2 areas on roof plates that are to be sent for analyses and replace with patch plates.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by roof replacement.	Hatch - May 3, 2017
3.4	Roof Platform	Repair	Install landing and railing on roof for access to sample hatch.	Dec. 2005-AITEC Out of Service Inspection Report	New platform and railing has been installed. However, this was attached with structural adhesive and meant to be a temporary attachment.	The platform should be welded to the tank.	Hatch - May 3, 2017
3.5	Roof Platform	Repair	The roof platform structural adhesive has failed and will need to be replaced or the platform installed by traditional methods during the next tank out of service.	Hatch - May 3, 2017		The platform should be welded to the tank.	
3.6	West Rim Vent	Replacement	Install screen on west rim vent.	Dec. 2005-AITEC Out of Service Inspection Report	Completed		Hatch - May 3, 2017
3.7	Roof Plates	Repair	There are two holes in the roof plates requiring patching or plate replacement.	Hatch - May 3, 2017		Covered by roof replacement.	
3.8	Roof plates		The roof plates have noticeable buckling and bulging	Hatch - May 3, 2017		Covered by roof replacement.	
4	**Tank Exterior**						
4.1	Stairway	Repair	Sections of the stairway have excessive corrosion. One weld on the handrail has completely corroded away.	Hatch - May 3, 2017		Clean stairs and reweld uprights when sufficient material is present.	
4.2	Grounding	Replacement	There is no evidence of grounding wires securely bonded to the tank and the compound. Consideration should be given to provide adequate grounding.	July 2016-Team In Service Inspection Report	This has not been addressed.	Install grounding to the tank.	Hatch - May 3, 2017
4.3	Concrete pedestal	Repair	The tank concrete base was observed to be fair condition with spalling & cracking observed. Repair the concrete pedestal spalling and cracks.	July 2016-Team In Service Inspection Report	This has not been addressed and has continued to deteriorate.	Repair all sections where the ringwall has deteriorated. Sections that require the tank to be jacked up should be repaired during the floor replacement. All cracks should be repaired to mitigate further deterioration.	Hatch - May 3, 2017
4.4	Tank nozzles	Repair	The repads on all nozzles have the telltale plugs inserted, it is recommended these be removed and filled with silicone.	July 2016-Team In Service Inspection Report	This has not been addressed.	Unplug repads and add silicone.	Hatch - May 3, 2017
4.5	External Coating	Repair	External coating was found in good condition with evidence of minor coating degradation. If not mitigated, further degradation may lead to external corrosion concerns	July 2016-Team In Service Inspection Report	Patching still required.	Patch recoat approximately 5%	Hatch - May 3, 2017
4.6	Exterior Shell		The exterior shell has noticeable buckling and bulging around the circumference at higher elevations of the tank. Buckling and bulging was noted in the roof of the tank.	Hatch - May 3, 2017			
4.7	Exterior Shell	Repair	The coating has noted corrosion and lack of coating in the joint between the tank and the adjacent building (north side).	Hatch - May 3, 2017		Blast and coat this section of the tank and restore the joint between the tank and adjacent building.	
4.8	Stairway	Repair	Install 12 stair treads and nosing on other treads and replace top landing.	Dec. 2005-AITEC Out of Service Inspection Report	Completed		Hatch - May 3, 2017
4.9	Nameplate	Replacement	Install a new data plate on the tank.	Dec. 2005-AITEC Out of Service Inspection Report	This has not been addressed.	Install a new name plate	Hatch - May 3, 2017
4.10	Sketch plate	Repair	Finish caulking remaining area of sketch plate to ring wall from east side near stairway counterclockwise to west side of block house.	Dec. 2005-AITEC Out of Service Inspection Report	This has not been addressed and has continued to deteriorate.	Covered by installation of asphalt impregnated fiber board during floor replacement.	Hatch - May 3, 2017

5	**Piping**						
5.1	Piping	Repair	The Tank associated piping has insulation failure and seam breakage was noted. It is recommended to be repaired to prevent further corrosion of the piping	July 2016-Team In Service Inspection Report	This has not been addressed and has continued to deteriorate.	Not in scope	Hatch - May 3, 2017
5.2	Pipe Supports	Repair	The Tank 1 associated pipe supports are heavily corroded.	Hatch - May 3, 2017		Not in scope	
5.3	Pipe Supports	Repair	There are pipe supports at grade.	Hatch - May 3, 2017		Not in scope	
5.4	Piping	Repair	There is a steam leak on the piping adjacent to the north side of the tank.	Hatch - May 3, 2017		Not in scope	
6	**Inspection**						
6.1	Tank External	Inspection	Complete a 5 year external inspection in 2023 (schedule date).	July 2016-Team In Service Inspection Report	Pending		Hatch - May 3, 2017
6.1	Tank Internal	Inspection	Complete a 10 year internal inspection in July 2019 (schedule date).	July 2016-Team In Service Inspection Report	Pending		Hatch - May 3, 2017
6.3	Inspection	Inspection	Cut out three areas on the tank floor 16"x16" at different locations and establish a moisture and hydrocarbon content in the soil under the tank.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by floor replacement	Hatch - May 3, 2017

Tank Deficiencies List - 2017 Holyrood Generating Station
Tank 2

No.	Location	Item Type	Deficiency	Original Observation Date	Comments	Recommended Repairs	Observation Date
1	**Compound**						
1.1	Compound	Repair	Compound surrounding the tank is in relatively poor condition with a great amount of rock on the west side of tank. Water is holding up around the tank. Vegetation is growing.	Dec. 2008-Team Out of Service Inspection Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Further improve site drainage to ensure groundwater does not hold up around the tank. Ensure grading slopes away from the tank. Remove all vegetation.	Hatch - May 3, 2017
1.2	Compound	Operational Instruction	Drainage needs to be maintained to ensure no acceleration of the underside corrosion.	March 2006-SGE Acres Evaluation Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Perform additional Tank Farm inspections to ensure excess water is not building up around the tank.	Hatch - May 3, 2017
2	**Floor**						
2.1	Floor Plate	Replacement	Recommend the removal of the existing floor coating system and recoating the floor and lower 1 meter of the tank shell	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.		Hatch - May 3, 2017
2.2	Tank Chine	Repair	Outside edge of sketch plate (chine) sitting on the concrete ring wall is sealed with some type of caulking which has failed in several places. Repair caulking.	Dec. 2008-Team Out of Service Inspection Report / July 2017 - Team In-Service Inspection Report	This has not been addressed and has continued to deteriorate.	Replace/repair caulking to ensure water does not pass underneath the tank.	Hatch - May 3, 2017
2.3	Tank Chine	Repair	There is an area of the chine to the right of the door sheet to be repaired.	Dec. 2008-Team Out of Service Inspection Report	Completed		Hatch - May 3, 2017
3	**Roof**						
3.1	Roof	Repair	Two roof leaks (middle section - west side) between channels 48-49 and 49-51. One roof leak (outer section - north side) at channel 94. These areas need to be repaired and consideration to blasting and painting the roof to reduce top side corrosion should be given.	Dec. 2008-Team Out of Service Inspection Report	This has not been addressed and has continued to deteriorate.	Patch and repair roof holes	Hatch - May 3, 2017
3.2	Roof Plate	Repair	The roof has 1 hole noted within the area permissible for inspection without fall arrest.	Hatch - May 3, 2017		Patch and repair roof holes	
3.3	Roof Vent	Repair	The screen mesh is missing from the roof vent.	Hatch - May 3, 2017 / July 2017-Team In-Service Inspection Report		Install new vent screen	
4	**Tank Exterior**						
4.1	Coating	Replacement	The tank coating is deteriorating	Hatch - May 3, 2017 / July 2017 Team In-Service Inspection Report	The tank coating has visibly deteriorated.	Recommend recoating entire tank.	
4.2	Shell Appurtenances and Stairway	Replacement	Minor scaling and minor corrosion noted. Blast and paint shell and nozzles to reduce plate corrosion pitting and rusting.	Dec. 2008-Team Out of Service Inspection Report	This has not been addressed and has continued to deteriorate.	Covered by tank coating replacement.	Hatch - May 3, 2017
4.3	Nameplate	Replacement	Data (name) plate is missing.	Hatch - May 3, 2017 / July 2017-Team In-Service Inspection Report		Install a new name plate	Hatch - May 3, 2017
4.4	Grounding		Tank does not have any grounding wires attached.	Hatch - May 3, 2017		Install grounding to the tank.	
4.5	Stairway	Repair	Multiple treads are missing nosing (~29).	Hatch - May 3, 2017		Clean stairs and weld noses when sufficient material is present.	
4.6	Exterior Shell	Repair	The coating has noted corrosion and lack of coating in the joint between the tank and the adjacent building (north side).	Hatch - May 3, 2017		Covered by tank coating replacement. Restore the joint between the tank and adjacent building	
4.7	Shell Appurtenances and Stairway	Repair	Stairway in fair condition, corrosion was noted on some treads and rails with repairs to be carried out.	Dec. 2008-Team Out of Service Inspection Report		Clean stairs and reweld uprights and treads when sufficient material is present.	Hatch - May 3, 2017
4.8	Tank Nozzles	Repair	Remove plugs from re pads and replace with silicone	Dec. 2008-Team Out of Service Inspection Report / July 2017 - Team In-Service Inspection Report	This has not been addressed.	Unplug repads and add silicone.	Hatch - May 3, 2017
4.9	Ringwall	Repair	Ringwall has spalling in several areas. Repair the spalling as required.	Dec. 2008-Team Out of Service Inspection Report / July 2017 - Team In-Service Inspection Report	This has not been addressed and has continued to deteriorate. Several areas around the circumference of the ringwall have excessive cracking and crumbling.	Repair all sections where the ringwall has deteriorated. Some sections will require the tank to be jacked up. All cracks should be repaired to mitigate further deterioration.	Hatch - May 3, 2017
5	**Piping**						
5.1	Pipe Support	Repair	Pipe supports to be repaired	Dec. 2008-Team Out of Service Inspection Report	This has not been addressed.	Not in scope	Hatch - May 3, 2017
5.2	Steam Traps	Repair	There are steam traps on the south and west side too close to the tank exposing the shell and ringwall to excessive moisture and causing coating damage. Recommend rerouting away from the tank.	Hatch - May 3, 2017		Not in scope	
5.3	Pipe Insulation	Repair	The tank associated piping has insulation failure and seam breakage. Cladding is no longer sealed in multiple locations. Insulation is wet and exposed.	Hatch - May 3, 2017		Not in scope	
5.4	PSV	Repair	There is a PSV with a blown gasket that is blowing steam. (North side of tank in tank building)	Hatch - May 3, 2017		Not in scope	
5.5	Pipe Supports	Repair	There are pipe supports at grade. Other supports are excessively corroded. Multiple slide plates are close to coming off the support. One support has risen off its beam and is now floating.	Hatch - May 3, 2017		Not in scope	
5.6	Piping	repair	There appears to be two steam leaks on the outlet piping (north side of the tank)	Hatch - May 3, 2017		Not in scope	

Tank Deficiencies List - 2017 Holyrood Generating Station
Tank 3

No.	Location	Item Type	Deficiency	Original Observation Date	Comments	Recommended Repairs	Observation Date
1	**Compound**						
1.1	Tank Dyke	Repair	Overall drainage performance is poor and contributing to accelerated corrosion of the floor plates. Drainage should be upgraded.	March 2006-SGE Acres Evaluation Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Perform additional Tank Farm inspections to ensure excess water is not building up around the tank.	Hatch - May 3, 2017
2	**Floor**						
2.1	Tank Floor	Replacement	Replace floor as per previous report.	June 2013 -Team API 653 Inspection Report	Completed		
2.2	Tank Chine	Repair	Severe corrosion was noted at Tank chine at north side of tank inside the shelter/shack.	June 2013 -Team API 653 Inspection Report	Repair completed. Severe corrosion was not present in this location during site visit.		Hatch - May 3, 2017
2.3	Tank Chine	Repair	Caulking is cracking and has separated from the chine in various locations around the ringwall circumference allowing water to pass under the bottom shell plate.	Hatch - May 3, 2017	Minor caulking breakdown.	Repair caulking where necessary to prevent water from passing underneath the tank.	Hatch - May 3, 2017
3	**Roof**						
3.1	Tank Roof	Monitoring	Roof plate needs to be continuously monitored for corrosion.	March 2006-SGE Acres Evaluation Report	No monitoring of the roof plate has been completed. Visual inspection (June 2013 - Team Report) was completed with minor corrosion and scale formation noted on bottom side of roof plates all over the tank.	Determine corrosion rate during next API Inspection	Hatch - May 3, 2017
3.2	Tank Roof	Repair	Coating needs maintenance.	March 2006-SGE Acres Evaluation Report	The tank was recoated. There have been large patches of paint that have flaked off. This should be repaired to reduce external corrosion.	The coating should be repaired.	Hatch - May 3, 2017
3.3	Roof Vents	Replacement	There are 7 roof vents with none having a screen installed in them.	June 2013 -Team API 653 Inspection Report / Hatch - May 3, 2017	Screens were installed on roof vents in the area of the roof that was accessible without fall protection.	Inspect the remaining roof vents to ensure they have screens installed.	Hatch - May 3, 2017
4	**Tank Exterior**						
4.1	Name Plate	Replacement	Replace nameplate.	June 2013 -Team API 653 Inspection Report	Completed but nameplate is currently illegible therefore the tank needs another replacement name plate.	Install new replacement name plate.	Hatch - May 3, 2017
4.2	Repads	Repair	Remove weep hole plugs and install silicone to prevent thread deterioration.	June 2013 -Team API 653 Inspection Report	Weep hole plugs were removed but the holes are now open and have no protection.	Clean the holes and install silicone .	Hatch - May 3, 2017
4.3	Concrete Ringwall	Repair	Evaluate and repair concrete ring spalling and cracking evident as well as exposed rebar.	June 2013 -Team API 653 Inspection Report	Completed with the exception of minor cracking that has since developed.	Repair all cracking to mitigate further deterioration.	Hatch - May 3, 2017
4.4	External Coating	Repair	Evaluate and repair coating. Paint failure in several areas around the tank shell. Appears not to be profiled properly prior to coating.	June 2013 -Team API 653 Inspection Report	This has not been addressed. The tank has multiple areas with noted coating damage on the east, south, and west sides.	Patch recoat areas with coating deterioration. Approximately 10% of the tank.	Hatch - May 3, 2017
4.5	Grounding		Tank does not have any grounding wires attached.	Hatch - May 3, 2017		Install grounding to the tank.	

Tank Deficiencies List - 2017 Holyrood Generating Station
Tank 4

No.	Location	Item Type	Deficiency	Original Observation Date	Comments	Recommended Repairs	Observation Date
1	**Compound**						
1.1	Compound	Repair	Dyke drainage improvements are required to reduce the corrosion of the floor plate.	March 2006-SGE Acres Evaluation Report	Site drainage has been improved. However, it appears as though groundwater is still high around the tanks. Efforts should be made to Drain the Tank Farm Sump more frequently.	Perform additional Tank Farm inspections to ensure excess water is not building up around the tank.	Hatch - May 3, 2017
2	**Floor**						
2.1	Floor Plate	Replacement	Recommend replacement of the floor and coating the floor and 1m of the lower shell in 2009.	March 2006-SGE Acres Evaluation Report	Completed		Hatch - May 3, 2017
2.2	Floor Plates	Repair	There are a total of 90 plates that had wall loss of 50% or greater. These require repair or patching in order to give the tank floor a six year life span	Aug. 2004-AITEC Out of Service Inspection Report	Completed during the floor replacement.		Hatch - May 3, 2017
2.3	Tank Chine	Repair	Caulking is starting to deteriorate in areas and moss is growing on it.	Hatch - May 3, 2017		Remove all vegetation and repair caulking deterioration to prevent water passage underneath the tank.	
3	**Roof**						
3.1	Roof Plate	Inspection	Needs to be continuously monitored for corrosion. During floor replacement an underside inspection of the roof plate and rafters is recommended. Maintenance of the coating system is required to prevent pitting corrosion.	March 2006-SGE Acres Evaluation Report	Unable to confirm if internal coating has been applied. No documentation to suggest the roof has been internally monitored.		Hatch - May 3, 2017
4	**Tank External**						
4.1	External Surface	Repair	Grind surface laminations in the three areas on the outside of the tank. Do MPI to ensure no indications are still remaining. If grinding brings shell below acceptable requirements, repair by welding using proper procedures.	Aug. 2004-AITEC Out of Service Inspection Report	Completed		Hatch - May 3, 2017
4.2	Nameplate	Replacement	Install a new data plate on the tank	Nov. 2010-Team Out of Service Inspection Report	Completed		Hatch - May 3, 2017
4.3	Grounding		Tank does not have any grounding wires attached.	Hatch - May 3, 2017		Install grounding to the tank.	
4.4	Exterior Shell		Buckling and bulging was noted around the tank circumference at higher elevations of the tank.	Hatch - May 3, 2017			
4.5	Tank Coating	Repair	There are multiple areas where the coating is damaged. The coating is damaged where the cable tray supports are welded to the tank. The coating has large sections on the east, south, and west side where it appears to be shedding or delaminating from the tank.	Hatch - May 3, 2017		Patch recoat areas with coating deterioration. Approximately 40% of the tank.	
4.6	Repads	Repair	Repad weep holes are open and do not have any coating protection	Hatch - May 3, 2017		Clean the holes and install silicone to prevent corrosion and thread damage.	
4.7	Tank Nozzle	Repair	Manway cover coating is damaged.	Hatch - May 3, 2017		Recoat the manway cover.	
4.8	Ringwall	Repair	Section of the concrete ringwall has failed and crumbled away.	Hatch - May 3, 2017		Repair the section where the ringwall has deteriorated.	

4.9	Stairway	Repair	Stair treads have multiple spots where the grating is corroded. Noses are also missing from the stairs (~71)	Hatch - May 3, 2017		Clean stairs, reweld treads, and install noses when sufficient material is present.	
4.10	Roof Platform	Repair	Platform is missing grating clips.	Hatch - May 3, 2017		Install grating clips on any platforms that have them missing.	
5	**Piping**						
5.1	Steam Traps	Repair	The steam traps on the south side of the tank are too close to the tank exposing the shell and ringwall to excessive moisture and causing damage. Recommend rerouting away from the tank.	Hatch - May 3, 2017		Not in scope	
5.2	Pipe Support	Repair	Pipe support pier is cracked and crumbling, exposed rebar (west side of tank)	Hatch - May 3, 2017		Not in scope	
5.3	Pipe Support	Repair	A pipe support on the north west side of the tank has considerable deterioration to the concrete support pier. The concrete has deteriorated from the top of the pier leaving a visible gap between the support plate and the pier. Steam traps adjacent to the pier are constantly blowing onto it which appears to have accelerated the problem.			Not in scope	
6	**Inspection**						
6.1	External Surface	Inspection	Sand blast the weld on the outside (closest to the shell) on row #1 which runs the entire tank circumference and do a vacuum box text to check for any rejectable indication in the areas where this row of plates is welded to the sketch plates.	Aug. 2004-AITEC Out of Service Inspection Report	This is no longer required as the floor was replaced in 2010.		Hatch - May 3, 2017
6.2	Tank Bottom	Analysis	Review the bottom settlement survey report from SGE Acres and determine if the settlement has occurred beyond the permissible limits of API 653 (appendix B)	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] A bottom settlement survey was completed in 2010 with the API Inspection.		Hatch - May 3, 2017
6.3	Rigid Tilt Survey	Analysis	Review the rigid tilt survey report from SGE Acres and make adjustments if required.	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] A bottom settlement survey, including rigid tilt, was completed in 2010 with the API Inspection.		Hatch - May 3, 2017
6.4	Tank Bottom	Inspection	Cut out four areas on the tank floor (16"x16") at different locations and establish a moisture and hydrocarbon content in the soil under the tank.	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] Floor was replaced in 2010.		Hatch - May 3, 2017
6.5	Tank External	Inspection	Complete a 10 year out of service inspection in Nov. 2020	Nov. 2010-Team Out of Service Inspection Report	Upcoming inspection.		Hatch - May 3, 2017
6.6	Tank Internal	Inspection	Complete a 5 year in-service inspection in Nov. 2015	Nov. 2010-Team Out of Service Inspection Report	Not Addressed.		Hatch - May 3, 2017

In October 2018, Team Industrial services investigated and recommended the possibility of extending the API 653 out-of-service inspection of Tank #1 originally scheduled for July 2019 to no later than December 2021 (including Tank #1 floor replacement) (Team Industrial Tank 1 - Inspection Interval Extension Report – October 2018; Team Industrial Letter - Tank 1 Oct 4 2018)

- Based on previous inspections and data collected in June 2018
- Based on Hydro having completing Team's recommended changes
- Based on tank farm being decommissioned in 2021

The key issues were:

- Corrosion and spalling of concrete ring beam (2016 in-service)
- Corrosion and possible delamination of chine area (2016 in-service)
- Corrosion concerns with roof (2016 in-service)
- Corrosion concerns with floor (2005 out-of-service)

The methodology used to determine if extending the out-of-service inspection interval was a possibility is as follows:

1. TEAM would conduct a preliminary inspection to determine if any additional issues have developed since the last out-of-service inspection was conducted in 2016. This also included determining the extent of preparatory work required.
2. TEAM would recommend the type and extent of preparatory work prior to completing the required inspections.
3. TEAM would complete a 100% magnetic particle inspection (MPI) in the critical external corner weld to ensure it has not been compromised by the deterioration of the concrete ring beam.
4. TEAM would complete an ultrasonic thickness survey (UT) of the chine area.
5. TEAM would complete an assessment of the roof panel thickness from previous report data.
6. TEAM would complete an assessment of the floor plate thickness from previous report data.

The results of the inspection were:

- No additional issues identified with MPI and UT inspections
- After 2016 a new rooof access platform was installed aligned to roof girders for load
- Floor assessment based on 2005 – any issues with corrosion >40% had been patched. Estimates were made of losses in other areas would have a life of 2022 (based on 2005 data and API 653 Table 4.4 assuming minimum thickness 0.100" where no means to detect and contain bottom leak)
- Corrosion rate likely less than historical due to better ground water drainage in Tank 1 area

Team recommended and Hydro completed following items:

- Repair of cracked and spalling areas of concrete ring beam
- Sealed chine and ring wall interface
- Reapplied coatings to tank chine area
- Resealed base plates on roof access platform (not completed)
- Installed tank nameplate in accordance with API 650 (not completed)
- Completed all 2016 Inspection report recommendations

In 2019 Team also developed a letter re the extension of the Out-of-Service inspection for tank #2 (Team Industrial Letter - Tank 2 2019 Oct.29)

- Next Out-of-Service inspection for tank #2 is Dec 2021 (previously extended from Dec 2018, with the extension based on an end of service life of HRD of March 2021 (same as Tank #1)
- Tank #1 floor replacement scheduled during same Dec 2021 Out-of-Service inspection
- TEAM calculations indicate next Out-of-Service Tank #2 inspection could be as late as Dec 2027 (per API Standard 653) pending DOMAE acceptance.
- If HRD still in-service they recommend Dec 2025 for next Out-of-Service Tank #2 inspection for logistical as well as environmental and generation constraints

In 2019 Team also developed a letter re the extension of the Out-of-Service inspection for tank #3 (Team Industrial NL Hydro Tank 3 API 653 In Service Inspection Report June 2018 and Team Industrial 092019 Tank 3 Letter):

- Next API 653 External inspection for tank #3 is Dec 2023 (every 5 years)
- Next API 653 Out-of-Service inspection for tank #3 is Dec 2020 based on previous internal inspection
- Hydro completed work to Team's satisfaction on outstanding issues
- TEAM calculations indicate next Out-of-Service Tank #3 inspection could be as late as June 2033 (per API Standard 653) pending DOMAE acceptance.
- If HRD still in-service they recommend June 2033 for next Out-of-Service Tank #3 inspection for logistical as well as environmental and generation constraints

In 2019 Team also developed a letter re the extension of the Out-of-Service inspection for tank #4 (Team Industrial NL Hydro Tank 4 API 653 In Service Inspection Report June 2018 and Team Industrial 092019 Tank 4 Letter Aug 29, 2019):

- Next API 653 External inspection for tank #4 is June 2023 (every 5 years)

- ▶ Next API 653 Out-of-Service inspection for tank #4 is Nov 2020 based on previous internal inspection
- ▶ Hydro completed work to Team's satisfaction on outstanding issues
- ▶ TEAM calculations indicate next Out-of-Service Tank #4 inspection could be as late as June 2027 (per API Standard 653) pending DOMAE acceptance.
- If HRD still in-service they recommend June 2027 for next Out-of-Service Tank #4 inspection for logistical as well as environmental and generation constraints

Light Oil Storage Tanks & Receiving System

The light oil storage tanks are relatively new, about 5 years old in 2010. 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 which may require inspections (and possible upgrades) in about 2022.

11.2.1.3 Condition Assessment

Main Oil Tanks

The existing tank farm consists of four 33,710 m3 (212,000 bbls) tanks. Each holds a fuel oil having 6.5 MMBTU/bbl, HFO cut with diesel fuel. Historically, fuel had been delivered by 200,000 bbl tankers about every 3 weeks. The plan is to have 3 tanks to March 2021.

- ▶ Tank 1 has a 2019 in-service visual out of service inspection scheduled. It has a roof water leak and may, without significant repair, must be decommissioned in 2021.
- ▶ Tank 2 has an API 653 In-Service 2017 inspection. Its 2018 Out of service inspection has been extended to 2021. For 3 tank operation beyond 2021, it is economically desirable to obtain a further extension. That extension has been requested but no response yet on approval. Technically, its remaining life could its extension to 2025 to 2027.
- ▶ Tank 3 had its last API In-Service inspection in 2012 with its next out service inspection /Condition Assess in 2022. For 3 tank operation beyond 2021, it is economically desirable to obtain an inspection extension. That extension has been requested, but no response yet on approval. Technically, its remaining life could its extension to 2033.
- ▶ Tank #4 had its last API In-Service inspection in 2010, with its next out of service planned for 2020. For 3 tank operation beyond 2021, it is economically desirable to obtain an inspection extension. That extension has been requested, but no response yet on approval. Technically, its remaining life could its extension to 2027.

In January 2019, the Government granted a "unique one time" extension on the Out of Service tank inspections to December 2021 (Jan 29 2019 Government Approval of Tanks 1 and 2 Out of Service Inspection Dates), which was based on the TEAM analysis and on the situation that the station was retiring in March 2021. Nevertheless, all four tanks would be operational until end of life (3 at least), and three beyond then.

Excerpt of correspondence below.

RE: API-653 Out-of-Service Internal Inspection Tank 1 & 2

This is in reference to your e-mail to Mansoor Ahmad dated October 18, 2018, in which you have made a request to extend the API-653 out-of-service inspection interval for tanks 1 & 2. This would enable four tanks to remain in service for Bunker C storage until the plant is decommissioned in 2021.

The Department has thoroughly reviewed the reports and the presentations given by TEAM Industrial Service TISI Canada Inc. (TEAM Industrial) regarding tanks 1 & 2, and upon review accept the findings and recommendations made by TEAM Industrial to safely extend the API-653 out-of-service inspection of tanks 1 & 2 to December 2021. It should be noted that the Department views this as a unique one-time situation, considering the fact that the facility will be ceasing operations in 2021. If Hydro decides to operate beyond the year 2021, then tanks 1 & 2 shall be inspected internally as per API-653 standards.

Finally, the Department requires that during this time (January 2019 to December 2021) Hydro shall provide dip measurements for tanks 1 & 2 by the end of the month following the month in which the dips were taken.

The average API out service inspection per tank is about $3.5 million without roof repairs and about $5 million including roof repairs It is expected that all API inspections will be deferred where possible to after 2023 where possible, including next day tank O/S inspection.

The current plan is to maintain the active size of the main tank farm for normal use to end of steam use in 2021, 2022, or 2023. Given the Condition of Tank #1, its continued use may not be possible without the $5 million or more expenditure. It is expected that the amount of main fuel required after March 2023 for the exercising of the units (each unit twice per year for 2 days at 70 to 150 MW) would be between 50,000 and 75,000 bbls. Full station emergency use at any time after March 2023 for 3 weeks (3 units x 150 MW to 170 MW x 3 weeks) is about 360,000 to 400,000 bbls. Each would also require #2 oil for start-up/warm-up. For cold standby with one unit acting as an auxiliary steam supply, additional main and light oil would be needed, at least during the winter readiness period.

A functioning suction heater plus main tank recirculation may be desirable going forward

Day Tank

The heavy oil day tank was replaced with the addition of Unit 3. The tank provides gravity flow to the supply pumps on each of the individual units. Unit 3 has a maximum 10.08Kg/s (80,000 Lb/hr) requirement for example supplied by 2 x 100% positive displacement pumps through 2 x 100% fuel oil steam heaters providing 99°C (210oF) oil to the units. There is a bypass around the day tank from the main tank farm, if required.

An out of service, internal inspection consistent with API 653 was undertaken in 2013. The magnetic flux of the entire floor plate identified as carried out. It and ultrasonic testing identified several issues:

- Severe material corrosion loss on west side of tank. A 4 ft x 20 ft long x ¼" thick patch plate was installed on the west side of the tank.
- Chime area requires backfill and compaction to allow proper runoff
- Additive tank structure base shows corrosion at ground – move outside dyke
- Diked area gravel undermined at edge tank and where liner exposed – repaired
- Broken insulation on pipelines within dyke area to prevent corrosion under insulation

- Repaint the tank to prevent further coating failure
- Roof and rafters corroded on underside – check at next inspection (max 10 years)
- Potential leak, but not found during vacuum box and magnetic particle testing

Its common header was also cleaned/refurbished in 2013. The repairs were subsequently made.

The Day Tank was cleaned out after the 2015 poor fuel incident. In 2019 there appears to be some significant deposition in the day tank resulting from the fuel make up and long sitting times. This has resulted in some pluggage of unit fuel filters and heaters. For the cold standby period and for fast starts, it may be necessary to install some active recycle back to the day tank through a recycle pump and auxiliary heater of some sort.

There was a 2017 visual inspection completed. The Day tank is subject to:

- API 5-year external tank inspection.
- API 10-year internal tank inspection, including a comprehensive inspection of all accessible tank components; and Out of service examinations and ultrasonic thickness surveys of floor, shell, roof, and nozzles.

A fire suppression system was installed in 2018 for the Day tank.

The last external inspection was in 2017 (required by Aug 2018). The next API out service inspection if required would be scheduled by August 2023, possibly deferred to sometime in the 2023 to 2027 period.

Overall, the day tank appears to be in fair to good condition.

Light Oil System

There is a light oil system for use in lighting off the steam generators, longer from a black start when atomizing steam is not available for some time for firing with #6 oil. The light oil is fired in the bottom level of burners. The light oil is provided from the station light oil tanks via a header to unit light oil pumps. Atomizing air is provided for the fuel and for purging on burner shutdown. There are two x 100% positive displacement pumps providing about 1034 kPa (150 psig). There is a recirculation system back to the tanks from the burner front header.

The light oil tanks are subject to API regulatory inspection requirements which may require inspections (and possible upgrades) in about 2022. Use of the diesel or new GT light oil tanks may be an alternative. The light oil system is considered able to make the March 2023 generation end of life date, and beyond if necessary.

Marine Terminal Condition

The marine terminal jetty had its annual PM in 2017 including a pile inspection and anode replacement. Its expected life assessment is to beyond 2023. No additional costs have been identified against the jetty, (but if emergency/standby generation is needed after March 2023, then additional inspections over the period 2022 to 2023 are likely). The heat tracing system from the jetty to the main oil tanks has been an issue over the last ten to fifteen years. It is expected that any additional costs will be addressed by the allowance for production costs.

The marine terminal loading arms were inspected in 2015 (Loading arms were inspected and repaired in 2015). The Marine terminal unloading lines breakaway valves were designed in 2018 and some examination of the jetty piles. (H355807-00000-240-030-0002 Marine Terminal Line Modification Feb 2018 – design; Hatch Report H355506-00000-240-230-0001, Holyrood Marine Terminal 10-Year Life Extension Study, March 21, 2018).

In 2019, Hatch carried out an inspection of the gravity fenders located on the front face of the jetty (Hatch Jetty Fenders - H361253-00000-240-024-0001pdf_0_V3-FINAL):

- Inspection started at fender #1 and moved across jetty to north side of jetty
- Excluded visual inspections looking down fenders via access from jetty deck, and measurements and no inspections accessing top fenders from jetty deck
- Waves did impact fender bottoms and some rocking of fenders seen
- Fenders 5 and 6 repaired and #4 replaced
- Wire rope tethers attached to wooden fenders very corroded
- Corrosion of diagonal bracing at shore arm supports and damage to concrete repairs supporting piles P-9 and S-8 a concern and should be monitored
- Continue monitoring of expansion joint gaps
- Continued deterioration of concrete reinforcements placed around some piles in 1980's – need monitoring, especially S-8

The expansion joints on the shore arm are not parallel since the early 1980's when some of the piles were damaged by ice. Visually, from the water, the gaps in the expansion joints are noticeable. We understand there is survey monitoring performed of the deck level monuments which are located on either of the expansion joints. We recommend this monitoring should continue.

In April 2017, large pieces of ice impacted the piled on the south side of the jetty and shore arm. These piles were inspected by drivers later in that year and no damage was identified. There is continued deterioration of the concrete reinforcement/protection that was placed around some of the piles in the early 1980s. This needs continuous monitoring. In particular, the concrete around Pile No. S-8 is in poor condition. For more detail and photographs on the pile inspections, please refer to Hatch Report No. H355506-00000-240-230-0001, titled Holyrood Marine Terminal 10-Year Life Extension Study, dated March 21, 2018.

wood.

Excerpts from Hatch Report H355506-00000-240-230-0001, Holyrood Marine Terminal 10-Year Life Extension Study, March 21, 2018.

2. Recommendations

For purposes of identification, the fenders are numbered consecutively 1 though 8 from South (Holyrood side) to North.

It is recommended the following be addressed as soon as possible and where possible prior to the next delivery of fuel to the terminal. Note these recommendations are similar to those made in the 2018 report.

1. Fender No. 2 needs to be replaced. See attached sketch of proposed replacement. Note: none of the concrete anchor bolts are in usable condition and an alternate method of securing the wooden fender surface is proposed. This is similar to the one used previously and installed by NL Hydro.
2. Fender No. 3 has one of the timbers falling away from the concrete at the top and is currently held in place by the wire rope tether. These tethers were not part of the original design but were attached to the top of the individual timbers in an attempt, by Hydro, to prevent the loss of the timbers should the concrete anchor bolts fail. This timber needs to be secured. See attached sketch of proposed method for securing this timber to the concrete fender and other wooden fenders. Note: it was determined from the site visit, reinstalling concrete anchor bolts would be difficult, costly and time consuming and an alternate method is proposed.
3. Fender No. 4 has a missing piece of the black UHMW plastic. The replacement of this is not critical but by having a missing piece this creates an edge which could over time help in the stripping off of other sections of the plastic. Note: this fender was replaced in 2013 and the plastic timer rubbing strip is not one continuous piece.
4. Fender 5 has one of the wire rope tethers laying across the face of the UHMW plastic. The tethers need to be inspected from the top of the fender to verify these are still secure and have not failed due to corrosion. The D-rubber bumper has been damaged on the south side and needs a piece of the metal removed immediately.
5. Fender No. 6 has one of the timbers missing and this needs to be replaced. The concrete anchors are missing. See attached sketch of proposed method for securing this timber to the concrete fender and other wooden fenders. Note: it was determined from the site visit reinstalling concrete anchor bolts would be difficult, costly and time consuming and an alternate method was proposed. The wire rope tether that held the top of this timber failed due to corrosion.
6. It is our understanding that the installation of the wire rope tethers by Hydro has been effective in reducing the number of lost timbers. We recommend that all tethers be inspected and replaced as needed. In our opinion, it is likely they are all significantly corroded and will require replacement.
7. Continue the monitoring of the shore arm expansion joints and survey the deck monuments.
8. Monitor the pile ice protection concrete on the shore arm piles. See pile shown in the Photographs Appendix. The ice protection has deteriorated significantly on pile No. S-8. Note the difference between the pictures taken in 2014 and this year. The concern is there is portion of the pile now exposed in the tidal zone where ice can contact the steel pile surface and can also push upward on the undersurface of the remaining concrete. We recommend this be repaired no later than next year. For the 2019-2020 winter season, we recommend this pile be monitored if there is a significant amount of ice in and around the jetty.

7. Conclusions

The marine terminal repairs and the majority of the recommendations have been completed satisfactorily. With yearly monitoring, the marine facilities should operate satisfactorily for an additional 10 years.

8. Recommendations

- The fendering on the jetty requires continuous monitoring. Measurements of the pin to support and center to center of the pins on the front fender arms should be checked every 5 years.
- The gaps at the land bridge expansion joints should be monitored yearly or as necessary based on ice conditions in and around the jetty.
- Any remediation recommendations for the jetty and bridge structures are highly dependent on the decommissioning date of the marine facilities. We understand there is a high likelihood the facilities will be in service until 2021 with decommissioning to take place sometime between 2021 and 2027. Based on these dates, no replacement of the pile anodes or repairs to the pile ice protection concrete and steel jackets are recommended.
- Ongoing yearly inspections are recommended to ensure no significant changes are happening to the structural components.
- A diving inspection of the piles and concrete should be conducted no later than 5 years from the last diving inspection, which occurred in 2017, to make sure there has been no significant deterioration of the structures. If there is significant ice against the marine facilities, similar to the winter and spring of 2017, additional surface and subsurface inspections should be considered once the ice has left the area.

11.2.1.4 Actions

Based on the condition assessment and planned end of generation life date of March 2023, no specific actions other than pursuing Regulatory Approval of Out of Service inspection extensions are recommended for the fuel systems (light and heavy oil), including those associated with the Marine Terminal.

Consideration to how to address the cold standby/emergency mode period from March 2023 onward should include:

- API inspections timing/regulatory approval for main and day oil tanks and light oil tanks
- Possible retrofit of a simple main tank recirculation and heating to minimize deposition (and its consequential impacts) resulting from extended periods of fuel storage
- Possible substitution of use of diesel and GT light oil tanks for main plant usage

11.2.1.5 Risk Assessment

Given the experience and maintenance since 2011 and the plans for inspections and maintenance, the risks from the heavy and light oil systems are expected to be low to achieve an end of normal generation date of March 2023, provided Regulatory Approvals of Out-of-Service inspections are received.

Significant technical and regulatory and financial risks exist going into the post March 2023 cold standby/emergency mode period related to fuel storage and delivery and fuel sludge deposition.

11.2.1.6 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment report, the primary change to the Life Cycle Curve is that the "Risk Area" will likely have shifted towards the 2020 to 2030 timeframe range. Light and heavy oil systems are expected to be acceptable up to generation end of life, with normal inspection and maintenance and PM work. Beyond 2023, subject to regulatory approval three main and the day heavy oil tank should be suitable for 2027 or beyond. The light oil tanks from the diesels and GT may be an option for light oil feed if needed beyond 2023.

11.2.1.7 Level 2 Inspection Requirements

Given the condition historical data reviewed, no Level 2's inspections are required, provided ongoing regulatory inspection and maintenance program and PM's continue. (

Excerpts from Hatch 2017 Report.

Tank 1 – Requires repairs, otherwise likely to be decommissioned in 2021.

5	**Piping**						
5.1	Piping	Repair	The Tank associated piping has insulation failure and seam breakage was noted. It is recommended to be repaired to prevent further corrosion of the piping	July 2016-Team In Service Inspection Report	This has not been addressed and has continued to deteriorate.	Not in scope	Hatch - May 3, 2017
5.2	Pipe Supports	Repair	The Tank 1 associated pipe supports are heavily corroded.	Hatch - May 3, 2017		Not in scope	
5.3	Pipe Supports	Repair	There are pipe supports at grade.	Hatch - May 3, 2017		Not in scope	
5.4	Piping	Repair	There is a steam leak on the piping adjacent to the north side of the tank.	Hatch - May 3, 2017		Not in scope	
6	**Inspection**						
6.1	Tank External	Inspection	Complete a 5 year external inspection in 2023 (schedule date).	July 2016-Team In Service Inspection Report	Pending		Hatch - May 3, 2017
6.1	Tank Internal	Inspection	Complete a 10 year internal inspection in July 2019 (schedule date).	July 2016-Team In Service Inspection Report	Pending		Hatch - May 3, 2017
6.3	Inspection	Inspection	Cut out three areas on the tank floor 16"x16" at different locations and establish a moisture and hydrocarbon content in the soil under the tank.	Dec. 2005-AITEC Out of Service Inspection Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.	Covered by floor replacement	Hatch - May 3, 2017

Tank 2 – Suitable for and applied for extension of Regulatory inspection/life to 2025-2027

6	**Inspection**						
6.1	Tank Internal	Inspection	Open and clean the tank in 6 years (2012) to verify the short term corrosion rate on plate 4-6 (16 inch 2" grid area)	Dec. 2008-Team Out of Service Inspection Report	This has not been addressed.		Hatch - May 3, 2017
6.2	Tank External	Inspection	Do a 5 year external inspection in 2013	Dec. 2008-Team Out of Service Inspection Report	Completed July 2017 by Team Industrial Services.		Hatch - May 3, 2017
6.3	Tank Internal	Inspection	Do a 10 year internal inspection in 2018	Dec. 2008-Team Out of Service Inspection Report	Upcoming internal inspection required.		Hatch - May 3, 2017
6.4	Roof Plate	Inspection	Recommend the roof plate be inspected for underside corrosion using interior scaffolding to determine if replacement needed	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.		Hatch - May 3, 2017
6.5	Roof Rafters	Inspection	Need to be inspected to determine if they are deflected in a similar manner to those in Tank 1.	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.		Hatch - May 3, 2017
6.6	Floor	Inspection	Recommended a floor scan be performed during proposed inspection in 2008.	March 2006-SGE Acres Evaluation Report	Unable to verify this as the tank was in operation. However, this did not appear to be completed in the documentation.		Hatch - May 3, 2017

Tank 3 – Suitable for and applied for Regulatory inspection extension of inspection/life to 2027-2033

6	**Inspection**						
6.1	Tank External	Inspection	Complete full API 653 out-of-service inspection after new floor is installed.	June 2013 -Team API 653 Inspection Report	Completed.		
6.2	Tank Floor	Inspection	Complete baseline ultrasonic thickness survey on new floor	June 2013 -Team API 653 Inspection Report	Completed.		
6.3	Tank Chine	Inspection	NDE on corner joint prior to welding annular ring	June 2013 -Team API 653 Inspection Report	Completed.		
6.4	Tank Chine	Inspection	NDE on completed corner weld.	June 2013 -Team API 653 Inspection Report	Completed both diesel test and MPI.		
6.5	Tank Floor	Inspection	Vacuum box test all floor seams after welding.	June 2013 -Team API 653 Inspection Report	Completed.		
6.6	Door sheet	Inspection	R/T and MPI door sheet after installation	June 2013 -Team API 653 Inspection Report	Completed.		
6.2	Tank Internal	Inspection	Tank requires a full API inspection in June 2023	June 2013 -Team API 653 Inspection Report	Upcoming inspection.		
6.3	Tank External	Inspection	Tank requires an external inspection in June 2018	June 2013 -Team API 653 Inspection Report	Upcoming inspection.		
6.4	Tank Roof	Inspection	Internal inspection of the roof plate underside and rafters should be completed in 2010.	March 2006-SGE Acres Evaluation Report	Completed during June 2013 API Inspection.		

Tank 4– Suitable for and applied for Regulatory extension of inspection/life to 2027

6	**Inspection**						
6.1	External Surface	Inspection	Sand blast the weld on the outside (closest to the shell) on row #1 which runs the entire tank circumference and do a vacuum box text to check for any rejectable indication in the areas where this row of plates is welded to the sketch plates.	Aug. 2004-AITEC Out of Service Inspection Report	This is no longer required as the floor was replaced in 2010.		Hatch - May 3, 2017
6.2	Tank Bottom	Analysis	Review the bottom settlement survey report from SGE Acres and determine if the settlement has occurred beyond the permissible limits of API 653 (appendix B)	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] A bottom settlement survey was completed in 2010 with the API Inspection.		Hatch - May 3, 2017
6.3	Rigid Tilt Survey	Analysis	Review the rigid tilt survey report from SGE Acres and make adjustments if required.	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] A bottom settlement survey, including rigid tilt, was completed in 2010 with the API Inspection.		Hatch - May 3, 2017
6.4	Tank Bottom	Inspection	Cut out four areas on the tank floor (16"x16") at different locations and establish a moisture and hydrocarbon content in the soil under the tank.	Aug. 2004-AITEC Out of Service Inspection Report	[Complete] Floor was replaced in 2010.		Hatch - May 3, 2017
6.5	Tank External	Inspection	Complete a 10 year out of service inspection in Nov. 2020	Nov. 2010-Team Out of Service Inspection Report	Upcoming inspection.		Hatch - May 3, 2017
6.6	Tank Internal	Inspection	Complete a 5 year in-service inspection in Nov. 2015	Nov. 2010-Team Out of Service Inspection Report	Not Addressed.		Hatch - May 3, 2017

11.2.1.8 Capital Projects

Capital enhancements for the system include if required: the required regulatory inspections, and any resulting as-found additional tank repairs:

Estimate - 2017 Holyrood Generating Station												
Tank 1												
No.	**Location**	**Item Type**	**Description**	**Comments**	**Quantity**	**Unit**	**$/Unit**	**Hours**	**$/Hour**	**Material Cost**	**Labour Cost**	**Cost**
1	**Compound**											
1.1	Compound	Repair	Walkovers are constructed of lumber. These should be replaced by steel walkovers	Replace existing walkovers with new galvanized steel walkovers.	2	each	$15,000			$30,000		$30,000
2	**Floor**											
2.1	Tank Bottom	Replacement	The calculated corrosion rate is 0.029". Based on this rate there was a total of 3 plates that had wall loss of 50% or greater which require repair or patching to give the tank floor a ten (10) year life span.	Based on previous corrosion rates the floor is overdue for replacement.								$950,000
2.2	Floor Plate	Repair	Recommend the removal of the existing floor coating system and recoating the floor and lower 1 meter of the tank shell.	Covered in floor replacement								
2.3	Inspection	Inspection	Cut out three areas on the tank floor 16"x16" at different locations and establish a moisture and hydrocarbon content in the soil under the tank.	Covered in floor replacement								
2.4	Floor to Shell Weld	Repair	Repair 30 areas on the top toe of the corner weld that had linear indications and inspect by magnetic particle.	Covered in floor replacement								
2.5	Floor to Corner Weld	Repair	Repair 11 areas on the floor to corner weld at the bottom toe of the weld where there is pitting corrosion and inspect by magnetic particle.	Covered in floor replacement								
2.6	Tank Bottom	Repair	Install patch plates on 12 areas of the floor where there is underside corrosion, topside pitting and areas where plates were cut out for soil samples. Inspect by MPI and vacuum box. Repair or replace 3 plates which had wall loss of 50% or greater.	Covered in floor replacement								
2.7	Sketch plate	Repair	Finish caulking remaining area of sketch plate to ring wall from east side near stairway counterclockwise to west side of block house.	Covered in floor replacement								
3	**Roof**											
3.1	Roof Plate	Replacement	The roof plate needs to be replaced in 5 years due to unusual underside corrosion. Recommend replacement. (2005 AITEC report also recommended a maximum 5 year remaining life with replacement in this timeframe)	Based on previous corrosion rates the roof is overdue for replacement.								$700,000
3.2	Roof Rafters	Inspection	Rafters need to be checked to determine cause of sweep. Further inspection should be carried out during roof plate replacement. There is a concern for the amount of deflection.	Issues encountered with rafters most likely point to rafters being undersized/corroded. Rafters are overdue for replacement								$200,000
3.3	Tank roof	Inspection	Cut out 2 areas on roof plates that are to be sent for analyses and replace with patch plates.	Covered in roof replacement								
3.4	Roof	Repair	Install landing and railing on roof for access to sample hatch.	Completed								
3.5	West Rim Vent	Replacement	Install screen on west rim vent.	Completed								
3.6	Roof Plates	Repair	There are two holes in the roof plates requiring patching or plate replacement.	Covered in roof replacement								
3.7	Roof plates		The roof plates have noticeable buckling and bulging	Covered in roof replacement								
4	**Tank Exterior**											
4.1	Stairway	Repair	Sections of the stairway have excessive corrosion. One weld on the handrail has completely corroded away.	Clean stairs and reweld uprights when sufficient material is present.								$6,000
4.2	Tank Chine	Repair	There is no seal in some areas at the base to chine interface to the concrete pedestal; this condition should be mitigated. The bottom plate chine projection also displayed signs of minor corrosion concerns.	Covered in floor replacement								
4.3	Grounding	Replacement	There is no evidence of grounding wires securely bonded to the tank and the compound. Consideration should be given to provide adequate grounding.	Estimate includes 6 grounding rods per tank and lugs/wiring.	6	each	$330	60	$120	$1,980	$7,200	$9,180
4.4	Concrete ringwall	Repair	The tank concrete base was observed to be fair condition with spalling & cracking observed. Repair the concrete ringwall spalling and cracks.	Concrete ringwall should be repaired.	16	m3	$2,000				$4,000	$2,570
4.5	Tank nozzles	Repair	The repads on all nozzles have the telltale plugs inserted, it is recommended these be removed and filled with silicone.	Unplug repads and add silicone.				2	$120		$240	$240
4.6	External Coating	Repair	External coating was found in good condition with evidence of minor coating degradation. If not mitigated, further degradation may lead to external corrosion concerns	Patch recoat approximately 5%								$40,000
4.7	Nameplate	Replacement	Install a new data plate on the tank.									$1,000
4.8	Roof Platform	Repair	The roof platform structural adhesive has failed and will need to be replaced or the platform installed by traditional methods during the next tank out of service.	Weld platform to tank roof.				16	$120		$1,920	$1,920
4.9	Exterior Shell		The exterior shell has noticeable buckling and bulging	Monitor condition of exterior shell.								
4.10	Exterior Shell	Repair	The caulking has noted corrosion and lack of coating in the joint between the tank and the adjacent building (north side).	Recaulking				16	$120		$1,920	$1,920
5	**Piping**											
5.1	Piping	Repair	The tank associated piping has insulation failure and seam breakage was noted. It is recommended to be repaired to prevent further corrosion of the piping	Not in scope								
5.2	Pipe Supports	Repair	The Tank 1 associated pipe supports are heavily corroded.	Not in scope								
5.3	Pipe Supports	Repair	There are pipe supports at grade.	Not in scope								
5.4	Piping	Repair	There is a steam leak on the piping adjacent to the north side of the tank.	Not in scope								
6	**Inspection**											
6.1	Tank External	Inspection	Complete a 5 year external inspection in 2023 (schedule date).									$50,000
6.2	Tank Internal	Inspection	Complete a 10 year internal inspection in July 2019 (schedule date).									$0
7	**Engineering**		Engineering was estimated at 5% of the total.									$97,142
8	**Contingency**		Contingency was estimated at 20% of the total.									$388,566
9	**Total**									$31,980	$15,280	$2,478,538

wood.

Estimate - 2017 Holyrood Generating Station
Tank 2

No.	Location	Item Type	Deficiency	Comments	Quantity	Unit	$/Unit	Hours	$/Hour	Material Cost	Labour Cost	Total Cost
1	**Coumpound**											
1.1	Compound	Repair	Walkovers are constructed of lumber. These should be replaced by steel walkovers	Replace existing walkovers with new galvanized steel walkovers.	2	each	$15,000			$30,000		$30,000
2	**Floor**											
2.1	Tank Chine	Repair	Outside edge of chine sitting on the concrete ring wall is sealed with some type of caulking which has failed in several places. Repair caulking.	Replace/repair caulking to ensure water does not pass underneath the tank.								$25,000
2.2	Floor Plate	Replacement	Recommend the removal of the existing floor coating system and recoating the floor and lower 1 meter of the tank shell	Preventative maintenance								$400,000
2.3	Tank Chine	Repair	There is an area of the chine to the right of the door sheet to be repaired.	Completed								
3	**Roof**											
3.1	Roof	Repair	Two roof leaks (middle section - west side) between channels 48-49 and 49-51. One roof leak (outer section - north side) at channel 94. These areas need to be repaired and consideration to blasting and painting the roof to reduce top side corrosion should be given.	Patch and repair roof holes.								$5,000
3.2	Roof Plate	Inspection	Recommend the roof plate be inspected for underside corrosion using interior scaffolding to determine if replacement needed	Complete during next API out of service inspection								
3.3	Roof Rafters	Inspection	Rafters need to be inspected to determine if they are deflected in a similar manner to those in Tank 1.	Complete during next API out of service inspection								
3.4	Roof Plate	Repair	The roof has 1 hole noted within the area permissible for inspection without fall arrest.	Patch and repair roof holes.								
4	**Tank Exterior**											
4.1	Shell Appurtenances and Stairway	Replacement	Minor scaling and minor corrosion noted. Blast and paint shell and nozzles to reduce plate corrosion pitting and rusting.	Covered by tank coating replacement.								
4.2	Nameplate	Replacement	Install new data (name) plate.									$1,000
4.3	Grounding	Replacement	There is no evidence of grounding wires securely bonded to the tank and the compound. Consideration should be given to provide adequate grounding.	Estimate includes 6 grounding rods per tank and lugs/wiring.	6	each	$330	60	$120	$1,980	$7,200	$9,180
4.4	Stairway	Repair	Multiple treads are missing nosing (~29).	Install nosing on stairs without.	29	each	$15	4	$120	$435	$480	$915
4.5	Coating	Replacement	The tank coating is deteriorating	Recommend recoating entire tank. The tank coating has visibly deteriorated.								$660,000
4.6	Exterior Shell	Repair	The coating has noted corrosion and lack of coating in the joint between the tank and the adjacent building (north side).	Covered by tank coating replacement.								
4.7	Shell Appurtenances and Stairway	Repair	Stairway in fair condition, corrosion was noted on some treads and rails with repairs to be carried out.	Clean stairs and reweld uprights and treads when sufficient material is present.								$2,500
4.8	Tank Nozzles	Repair	Remove plugs from re pads and replace with silicone	Unplug repads and add silicone.								$1,000
4.9	Concrete ringwall	Repair	Ringwall has spalling in several areas. Repair the spalling as required.	Ringwall should be repaired.	16	m3	$2,000			$32,000		$32,000
5	**Piping**											
5.1	Pipe Support	Repair	Pipe supports to be repaired	Not in scope								
5.2	Steam Traps	Repair	There are steam traps on the south and west side too close to the tank exposing the shell and ringwall to excessive moisture and causing coating damage. Recommend rerouting away from the tank.	Not in scope								
5.3	Pipe Insulation	Repair	The tank associated piping has insulation failure and seam breakage. Cladding is no longer sealed in multiple locations. Insulation is wet and exposed.	Not in scope								
5.4	PSV	Repair	There is a PSV with a blown gasket that is blowing steam. (North side of tank in tank building)	Not in scope								
5.5	Pipe Supports	Repair	There are pipe supports at grade. Other supports are excessively corroded. Multiple slide plates are close to coming off the support. One support has risen off its beam and is now floating.	Not in scope								
5.6	Piping	repair	There appears to be two steam leaks on the outlet piping (north side of the tank)	Not in scope								
6	**Inspection**											
6.1	Tank Internal	Inspection	Open and clean the tank in 6 years (2012) to verify the short term corrosion rate on plate 4-6 (16 inch 2" grid area)									
6.2	Tank External	Inspection	Do a 5 year external inspection in 2013									
6.3	Tank Internal	Inspection	Do a 10 year internal inspection in 2018									
7	**Engineering**		Engineering was estimated at 5% of the total.									$58,330
8	**Contingency**		Contingency was estimated at 20% of the total.									$233,319
9	**Total**									$64,415	$7,680	$1,458,244

Estimate - 2017 Holyrood Generating Station
Tank 3

No.	Location	Item Type	Deficiency	Comments	Quantity	Unit	$/Unit	Hours	$/Hour	Material Cost	Labour Cost	Total Cost
1	**Compound**											
2	**Floor**											
2.1	Tank Floor	Replacement	Floor Needs to be replaced by 2010. Floor and lower shell should be coated.	Completed								
2.2	Tank Chine	Repair	Caulking is cracking and has separated from the chine in various locations around the ringwall circumference allowing water to pass under the bottom shell plate.	Repair areas where caulking is starting to deteriorate to prevent water passage and tank underside corrosion.								$12,000
3	**Roof**											
3.1	Tank Roof	Monitoring	Roof plate needs to be continuously monitored for corrosion.	Determine corrosion rate during next API Inspection								
3.2	Tank Roof	Repair	Coating needs maintenance.	Blast and patch areas with coating deterioration								$70,000
4	**Tank Exterior**											
4.1	Name Plate	Replacement	Replace nameplate.	Completed but nameplate is currently illegible therefore the tank needs another replacement name plate.								$1,000
4.2	Grounding	Replacement	There is no evidence of grounding wires securely bonded to the tank and the compound. Consideration should be given to provide adequate grounding.	Estimate includes 6 grounding rods per tank and lugs/wiring.	6	each	$330	60	$120	$1,980	$7,200	$9,180
4.3	Roof Platform	Repair	The roof platform is missing grating clips and kickplates	Install grating clips and kick plates								$500
4.3	Concrete Ringwall	Repair	Evaluate and repair concrete ring spalling and cracking evident as well as exposed rebar.	Completed with the exception of minor cracking that has since developed. Repair ringwall cracks to prevent further deterioration	1	m3	$1,000	20	$120	$1,000	$2,400	$3,400
4.2	Repads	Repair	Remove weep hole plugs and install silicone to prevent thread deterioration.	Weep hole plugs were removed but the holes are now open and have no protection.								$1,000
4.6	Stairway	Repair	Stair treads are missing nosing (~70)	Clean stairs and reweld treads when sufficient material is present. Install noses.	70	each	$15	8	$120	$1,050	$960	$2,010
4.4	External Coating	Repair	Evaluate and repair coating. Paint failure in several areas around the tank shell. Appears not to be profiled properly prior to coating.	This has not been addressed. The tank has multiple areas with noted coating damage on the east, south, and west sides. Patch recoat areas with coating deterioration. Approximately 10% of the tank.								$130,000
4.8	Exterior Shell	Repair	The caulking in the joint between the tank and adjacent building is deteriorating.	Repair joint between building and tank				16	$120		$1,920	$1,920
5	**Piping**											
5.1	Steam Traps	Repair	The steam traps on the south side of the tank are too close to the tank exposing the shell and ringwall to excessive moisture and causing damage. Recommend rerouting away from the tank.	Not in scope								
5.2	Tank (west) piping	Repair	A valve on the west side of the tank has a blown gasket. Steam has punctured a hole in the insulation and is continually blowing. (Valve V604)	Not in scope								
5.3	Steam Traps	Repair	Steam traps adjacent to the bunker lines (west side of the tank) are not functioning properly and continuously blowing steam to atmosphere.	Not in scope								
5.4	Pipe Support	Repair	Pipe support pier on the south side of the tank (closest to south tank inlet nozzle) is cracked and has settled which may be causing excessive nozzle loads on the tank. Multiple supports around tank 3 are not grouted to the pier/pedestal.	Not in scope								
6	**Inspection**											
6.1	Tank Internal	Inspection	Tank requires a full API inspection in June 2023.									
6.2	Tank External	Inspection	Tank requires an external inspection in June 2018.									
7	**Engineering**		Engineering was estimated at 5% of the total.									$11,551
8	**Contingency**		Contingency was estimated at 20% of the total.									$46,202
9	**Total**									$4,030	$12,480	$288,763

Estimate - 2017 Holyrood Generating Station												
Tank 4												
No.	**Location**	**Item Type**	**Deficiency**	**Comments**	**Quantity**	**Unit**	**$/Unit**	**Hours**	**$/Hour**	**Material Cost**	**Labour Cost**	**Total Cost**
1	**Compound**											
2	**Floor**											
2.1	Tank Chine	Repair	Caulking is starting to deteriorate in areas and moss is growing on it.	Repair areas where caulking is starting to deteriorate to prevent water passage and tank underside corrosion.								$12,000
3	**Roof**											
3.1	Roof Plate	Inspection	Needs to be continuously monitored for corrosion. During floor replacement an underside inspection of the roof plate and rafters is recommended. Maintenance of the coating system is required to prevent pitting corrosion.	Determine corrosion rate during next API inspection.								
4	**Tank Exterior**											
4.1	External Surface	Repair	Grind surface laminations in the three areas on the outside of the tank. Do MPI to ensure no indications are still remaining. If grinding brings shell below acceptable requirements, repair by welding using proper procedures.	Completed								
4.2	Nameplate	Replacement	Install a new data plate on the tank									$1,000
4.3	Grounding	Replacement	There is no evidence of grounding wires securely bonded to the tank and the compound. Consideration should be given to provide adequate grounding.	Estimate includes 6 grounding rods per tank and wiring.	6	each	$330	60	$120	$1,980	$7,200	$9,180
4.4	Exterior Shell		Buckling and bulging was noted around the tank circumference at higher elevations of the tank.	Monitor condition of exterior shell.								
4.5	Tank Coating	Repair	There are multiple areas where the coating is damaged. The coating is damaged where the cable tray supports are welded to the tank. The coating has large sections on the east, south, and west side where it appears to be shedding or delaminating from the tank.	Patch recoat approximately 40%								$270,000
4.6	Repads	Repair	Repad weep holes are open and do not have any coating protection	Clean weep holes and fill with silicone								$1,000
4.7	Tank Nozzle	Repair	Manway cover coating is damaged.	Patch recoat (covered in tank patch)								$500
4.9	Ringwall	Repair	Concrete ringwall has failed and crumbled away in multiple sections.	Ringwall should be repaired.	0.25	m3	$650	12	$120	$163	$1,440	$1,603
4.10	Stairway	Repair	Stair treads have multiple spots where the grating is corroded. Noses (~71) are also missing from the stairs.	Clean stairs and reweld treads when sufficient material is present. Install noses.	71	each	$15	8	$120	$1,065	$960	$2,025
4.11	Grounding		Tank does not have any grounding wires attached.	Estimate includes 6 grounding rods per tank and lugs/wiring.	6	each	$330	60	$120	$1,980	$7,200	$9,180
4.13	Roof Platform	Repair	Platform is missing grating clips.	Install missing grate clips.								$200
5	**Piping**											
5.1	Steam Traps	Repair	The steam traps on the south side of the tank are too close to the tank exposing the shell and ringwall to excessive moisture and causing damage. Recommend rerouting away from the tank.	Not in scope								
5.2	Pipe Support	Repair	Pipe support pier is cracked and crumbling, exposed rebar (west side of tank)	Not in scope								
5.3	Pipe Support	Repair	A pipe support on the north west side of the tank has considerable deterioration to the concrete support pier. The concrete has deteriorated from the top of the pier leaving a visible gap between the support plate and the pier. Steam traps adjacent to the pier are constantly blowing onto it which appears to have accelerated the problem.	Not in scope								
6	**Inspection**											
6.1	Tank External	Inspection	Complete a 10 year out of service inspection in Nov. 2020									
6.2	Tank Internal	Inspection	Complete a 5 in-service inspection in Nov. 2015									
7	**Engineering**		Engineering was estimated at 5% of the total.									$15,334
8	**Contingency**		Contingency was estimated at 20% of the total.									$61,338
9	**Total**									$5,188	$16,800	$383,359

As well, possible retrofit of a simple main tank recirculation and heating system for at least one or two main tanks and for the day tank should be examined to minimize deposition (and its consequential impacts) resulting from extended periods of fuel storage

11.2.2 Waste Water Treatment Plant (WWTP)

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 Chapter 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 (No major change since 2010/11 C.A and 2017 update Report)

11.2.2.2 History (No major change since 2010/11 C.A and 2017 update Report)

11.2.2.3 Inspection and Repair History

Waste Water Treatment Plant (WWTP) Batch Reactor & Building: Although no major inspections were identified as having been undertaken, a high level visual inspection when the settling tank and its auxiliaries were empty indicated that the equipment is in good condition.

Since 2007 (the adoption of the new fuel oil), less boiler cleanup water has meant there is more time to access the mechanical settler and filter press for maintenance and inspection.

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 noted.

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.

There are OHSA air quality safety issues around basin access (exit routes). Access is restricted.

From an external visual inspection of the equalization basin building, it was clear both the interior and exterior continues to be affected by the very humid atmosphere. Ventilation systems are not very effective and have experienced corrosion. The roofing is considered by staff to be unsafe. The structural steel has also experienced significant rusting.

Oily Water Separator and Piping: The 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.

An inspection of one of the North tanks was undertaken about five years ago, but no report was available. The tanks we identified as being in fair shape, with some internal corrosion. Nevertheless, the north tanks were replaced.

Inspections have not been done on the south oily water separators. There was a plan to do these inspections in 2020 as part of an overall Level 2 project, but this is not proceeding. A Level 2 inspection is likely warranted in the 2021 to 2025 period.

Site Waste Water Piping: Some review of plant drains have been undertaken since 2011. No specific inspection documentation was available that indicated the condition of the underground waste water piping. Since some of the equipment has only been in place since the WWTP in-service date of 1994, it is still generally expected to be in good shape.

11.2.2.4 Condition Assessment

The condition assessment of the waste water treatment plant is somewhat uncertain. Some concern with basin building and oily water separators remain, but access is restricted. With ongoing monitoring and maintenance, they should be able to meet a March 2023 generation end of life. Continued use beyond 2043 for synchronous generation use likely require some re-assessment of system requirements in 2022 to 2023.

11.2.2.5 Actions

Based on the condition assessment, a Level 2 Condition Assessment of the Oily Water Separator system is likely warranted. Some refurbishment/replacement of waste water treatment equipment/motors may be warranted and should be assessed.

11.2.2.6 Risk Assessment

The risk assessment associated with the waste water treatment plant, both from a technological perspective and a safety perspective, has not significantly change since 2011 and 2017, with all be low.

The condition of the South oily water separators is uncertain, hence is the likelihood of a failure and an environmental incident. There was a plan to do these inspections in 2020 as part of an overall Level 2 project, but this is not proceeding. A Level 2 inspection is likely warranted in the 2021 to 2025 period..

11.2.2.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment and 2017 update report, the Life Cycle Curve would suggest only some concern about the oily water separator. All others should meet the 2023 end of generation life timeline. The issue with the oil separation is subject to inspection information required.

11.2.2.8 Level 2 Inspections

Given the condition historical data reviewed, a Level 2's inspection an assessment of the south oily water separators is warranted. This needs to be assessed given ongoing inspection and maintenance program and PM's as well as confined space safety risks. A Level 2 inspection is likely warranted in the 2021 to 2025 period.

An assessment of the Waste water treatment process equipment/motors is warranted.

11.2.2.9 Capital Projects

No additional capital enhancements for the system are identified, although capital work in 2023-2025 period on oily water separators and waste water treatment equipment/motors may be needed based on inspections/assessments for continued standby operation or for Unit 3 synchronous condensing operation.

11.2.3 Asset 9739 – Water Treatment Plant (WTP) System

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 7185 WTP & MCC C5 7212 WTP Sulphuric Acid System 7213 WTP Flocculent Chem Inj 7214 WTP Primary Train 7220 WTP Mixed Bed 7410 WT MCC C10 7422 WTP Clarifier System 8748 WTP & Aux Blr MCC WTP-34 9864 WTP Sand Filter 9879 WTP Clearwell System 9995 6400 Chem Inj 10037 WTP Caustic System

11.2.3.1 Description (No major change since 2010/11 C.A and 2017 update Report)

11.2.3.2 History

The addition of a second raw water supply line in 2018 has eliminated it as a single contingency failure item.

The domestic water supply line was upgraded in 2018.

The plant fire water system which draws its supply from the freshwater pond and which feeds individual fire stands using asbestos concrete piping has had several recent piping failures in 2017-2019. Repairs were made at the time of failure.

The underground drainage system was upgraded in 2017.

11.2.3.3 Inspection and Repair History (No major change since 2010/11 C.A and 2017 update Report)

Regular inspections, maintenance and PM work has continued on regular basis. No major new replacements since 2011. A Level 2 assessment was completed after 2011.

The plant fire water system was planned to be inspected in 2020 as part of a larger Level 2 Condition Assessment project that has recently been cancelled/deferred. It is likely that some repair work is needed in 2020, and a staged replacement project is warranted in 2021 through 2023.

11.2.3.4 Condition Assessment

The water treatment plant system given maintenance and improvements since 2011 are considered in good enough condition to be able to achieve generation end of life in March 2023, and with ongoing PM's and inspection to meet a 2027+ cold standby/emergency generation mode. Plant has indicated concerns with the acid/caustic tanks in the water treatment plant in the short term and with overall facility post steam period for domestic and generator GSCW water.

The plant fire water system, given recent failures of some pipe sections, is likely in poor condition and in need of upgrade of some sections. The plant fire water system was planned to be inspected in 2020 as part of a larger Level 2 Condition Assessment project that has recently been cancelled/deferred. It is likely that some repair work is needed in 2020 and a staged replacement project is warranted in 2021 through 2023.

11.2.3.5 Actions

Based on the condition assessment and the end of generation date of March 2023, no action beyond continued inspections, maintenance and PM's is warranted for the water treatment plant in short term. The role of the Unit treatment systems should be examined for the post steam period, in particular the condition of the acid/caustic tanks in shorter term.

The plant fire water system needs to be repaired as required in 2020 and a staged replacement project is warranted in 2021 through 2023.

11.2.3.6 Risk Assessment

The risk assessment associated with the water treatment plant, both from a technological perspective and a safety perspective, has no high-risk elements that would likely significantly impact availability of generation to March 2023. For post steam, an assessment of the condition of and the requirements for the water treatment plant is required.

The recent localized failures of the plant fire water system raise an immediate safety concern. Repairs as required should be made in 2020 and a plan for staged replacement considered.

11.2.3.7 Life Cycle Curve and Remaining Life

Given the experience since the 2010/11 Condition Assessment C.A and 2017 update report, the water treatment plant (WTP) system exceeds the end of generation date of March 2023.

The plant fire water system is of immediate concern and following inspection in 2020, it should be repaired as required.

11.2.3.8 Level 2 Inspection Requirements

For the water treatment plant, no further Level 2 inspections are required before the end of generation life in March 2023, provided current plant inspection and maintenance program is maintained. For post steam, an assessment of the needs is required.

The plant fire water system is of immediate concern and rather than an inspection project repairs as required should be made in 2020, and a staged repair/replace project put into place.

11.2.3.9 Capital Projects

No additional capital enhancements for the system are suggested for the water treatment plant in the short term, but for post steam an assessment of the condition of and need for the water treatment plant services (i.e. acid and caustic tanks) is required..

Repairs/replacements of the plant fire water system as required should be made in 2020, and a staged repair/replace project put into place.

11.2.4 Assets 6717 and 8680 – Diesel Gensets

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 8680 Stage 2 Auxiliary Diesel Generator

11.2.4.1 Description (No major change since 2010/11)

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 replaced in 2015 and would then be expected to last to 2043.

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 tiebreakers.

11.2.4.2 History (No major change since 2010/11 C.A and 2017 update Report)

The Stage 2 diesel was replaced in 2015.

Extended stacks were added in 2018 to meet ground level emissions concentrations.

11.2.4.3 Condition Assessment

The diesel gensets are considered in good condition and able to achieve generation end of life in March 2023. They should/will continue to provide emergency service with normal maintenance based on condition and equivalent operating hours beyond 2030.

11.2.4.4 Actions

Based on the Condition Assessment, no Actions are recommended beyond maintaining regular PM's/inspections for the diesel gensets:

11.2.4.5 Risk Assessment

The risk assessment associated with the diesel gensets, both from a technological perspective and a safety perspective, are all now low.

11.2.4.6 Life Cycle Curve and Remaining Life

Given the replacement of one of the diesel gensets, the system is expected to reach the March 2023 end date for generation.

11.2.4.7 Level 2 Inspections

Given the condition historical data reviewed, no Level 2's inspections are required, provided ongoing inspection and maintenance program and PM's continue.

11.2.4.8 Capital Projects

No additional capital enhancements for the system are suggested.

12. Level 2 Requirements Summary

Level 2 inspections were identified in Chapters 8 to 11. Summary level information on what Level 2 activities should be undertaken is provided in this chapter. It is summarized by Major Plant Area, but no costs were included in the scope of this update.

12.1 Level 2 Activities Summary

Tables 12-1, 12-2, 12-3, and 12-4 are summaries of Level 2 activities identified for Units 1,2,3, and Common, respectively. Priorities assigned by WOOD, with Priority 1 being the highest priority.

Table 12-1 Unit 1 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
8.1.3.8	Unit 1	6723 – Unit 1 Electrical & Control Systems	Monitor cables, bus duct, power centre B AAB2.	3
8.1.3.8	Unit 1	6723 – Unit 1 Electrical & Control Systems	Assess Stage 1 switchgear for a) the one synchronous condenser unit case, including station service supply; b) all three units in cold standby/emergency operation mode after March 2023.	2
8.1.4.8 8.2.10.8	Unit 1	280182 – Unit 1 Electrical & Control Systems	Concrete beam of East Cooling Water Sump,– inspection and repair as required	2
8.2.1.8/11	Unit 1	6699 – Unit 1 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
8.2.2.8	Unit 1	6708 – Unit 1 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U1 HP feedwater discharge piping	1
8.2.3.8	Unit 1	6708 – Unit 1 Feed Water System HP Heat Exchangers	Assess need for Level 2 inspection of U1 Deaerator Internals	3
8.2.5.8	Unit 1	271316 – Unit 1 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1
8.2.6.8	Unit 1	8777 – Unit 1 FD Fans and System	Level 2 Unit 1 FD fan internals and APH's	2
8.2.7.8	Unit 1	6919 – Unit 1 Stack and Breaching	No Level 2 (Continue stack regulatory inspections. Undertake stack re-coating in 2021-2023 period.	2

Section	Unit	Asset	Activity	Priority
8.2.9.8	Unit 1	271309 – Unit 1 Steam Turbine	2021 Level 2 U1 Steam Turbine – stud creep assessment (for those above 850ºF); LP L0 borescope; vibration issues retest as part of inspection/overhaul.	1

Table 12-2 Unit 2 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
9.1.3.8	Unit 2	8152 – Unit 2 Electrical & Control Systems Associated with Generators	Monitor cables, bus duct, power centre B AAB2	3
9.1.3.8	Unit 2	8152 – Unit 2 Electrical & Control Systems Associated with Generators	Assess Stage 1 switchgear for a) the one synchronous condenser unit case, including station service supply; b) all three units in cold standby/emergency operation mode after March 2023.	2
9.1.4.8 9.2.10.8	Unit 2	271486 – Unit 2 Cooling Water Systems Associated with Generators	Cooling Water Sump, intake, and discharge piping – video inspection and repair as required	3
9.2.1.5/8	Unit 2	7786 Unit 2 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
9.2.2.8	Unit 2	7978 – Unit 2 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U2 HP feedwater discharge piping	1
9.2.3.8	Unit 2	8017 – Unit 2 Feed Water System - Deaerator	Level 2 monitor testing of U2 Deaerator Internals	3
9.2.5.8	Unit 2	271326 – Unit 2 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1
9.2.1.5	Unit 2	7786 Unit 2 Boiler System	Inspect Unit 2 Boiler Stop Valves and based on results, assess removal/refurbish/replace options	2
9.2.6.8	Unit 2	7786 – Unit 2 FD Fans and System	Level 2 Unit 2 FD fan internals and APH's	2
9.2.7.8	Unit 2	7900-Unit 2 Stack and Breeching	No Level 2 (Continue stack regulatory inspections. Undertake stack re-coating in 2021-2023 period.	2

Section	Unit	Asset	Activity	Priority
9.2.9.8	Unit 2	271317 – Unit 2 Steam Turbine	2020 Level 2 U2 Steam Turbine – stud creep assessment (for those above 850ºF); LP L0 borescope as part of 2020 valve/generator inspection/overhaul.	1

Table 12-3 Unit 3 Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
10.1.3.8	Unit 3	8712 – Unit 3 Electrical & Control System Associated with Generators	Monitor cables, bus ductUAT3 SA T34 aux transformer	3
10.1.4.8	Unit 3	271678 – Unit 3 Cooling Water Systems Associated with Generators	Visual inspection of U3 Cooling Water Sump, intake, and discharge piping in 2021-2023.	3
10.2.1.8	Unit 3	8336 – Unit 3 Boiler System	Continue Level 2 inspections and tests as per Level 2 Boiler assessments.	1
10.2.1.8	Unit 3	8336 – Unit 3 Boiler System	Level 2 inspections of Steam Drum internals	2
10.2.2.8	Unit 3	8611 – Unit 3 Feed Water System HP Heat Exchangers	Level 2 monitor testing of U3 HP feedwater discharge piping	1
10.2.3.8	Unit 3	8571 – Unit 3 Feed Water System – Deaerators	Level 2 monitor testing of U3 Deaerator Internals	3
10.2.5.8	Unit 3	271677 – Unit 3 Condenser	Level 2 Condenser waterbox inspection and repair (waterbox/tubesheet thickness checks)	1
10.2.6.8	Unit 3	8777 – Unit 3 FD Fans and System	Level 2 Unit 3 FD fan internals and APH's	3
10.2.7.8	Unit 3	8448 – Unit 3 Stack and Breeching	No Level 2 (Continue regulatory stack inspections and monitor degradation of stacks and liners). Undertake stack re-coating in 2021-2023.	2
10.2.9.8	Unit 3	271675 – Unit 3 Steam Turbines	Level 2 inspection and repair Main Steam Chest; turbine studs, LP LO borescope during 2022 generator and turbine valves inspection	1

Table 12-4 Common Facilities Level 2 Activities Prioritized Summary

Section	Unit	Asset	Activity	Priority
11.2.2.8	Common	1297 Waste Water Treatment Plant	Level 2's inspection assessment of the south oily water separator in the 2021 to 2025 period An assessment of the Waste water treatment process equipment/motors is warranted.	2
11.2.1.7	Common	Oil Storage	Tanks 2,3,4 inspections and repairs if extension not granted – per API letters (for 2023 Life and for beyond 2023)	1
11.2.2.5	Common	Waste Water Treatment Plant (WWTP)	Level 2 Condition Assessment of the Oily Water Separator system (South)	2

13. Summary Capital Plan Assessment and Suggestions

13.1.1 2019 Capital Plan Investments for March 2021 End of Steam Generation

The Holyrood 2019 capital plan is presented in Table 13-1 below (also as Table 5.2 in Chapter 5.4.2). It assumed an end of steam date of March 31, 2021. As such, it was noted that this plan did not include recent supplemental projects that HRD TGS consider necessary for its end of steam life to be extended beyond March 31, 2021 to March 31, 2023. (Note: It also this does not include boiler overhauls, which are not capital.)

Wood are substantially in agreement with the elements of the plan. Most of these are for Stage 2/Unit 3 facilities or common facilities and will be required for ongoing plant and Unit 3 synchronous condensing operation. Wood also agrees with the concept that some of the larger items will be re-examined in 2020/2, primarily those not associated with Unit 3's continued use as a Synchronous Condenser and/or are indicated as "SUPPLEMENTAL" and are post 2021.

Table 13-1
2019-2024 Capital Plan – For End of Steam Service of March 2021

2019 HTGS Capital Plan (2020-2024)						
Year	Project	2020	2021	2022	2023	2024
2020	Rewind Unit 3 Generator Stator	1,359.6	5,789.0			
	Upgrade UPS 3 & 4	266.7				
	Install Plant Heating System (Will be SUPPLEMENTAL)	519.1	6,953.7			
	Upgrade Waste Water Basin Building (Submit for 2021 or SUPPLEMENTAL)	116.7	1,362.7			
	Thermal In Service Failures	1,250.0				
2021	Replace One of North or South Instrument Air Receiver Systems Unit 3		753.0			
	Inspect and Overhaul Stacks		500.0			
	Upgrade Property Fencing		50.0	50.0		
	Replace Stage II Electrical Distribution Equipment		2,513.2	2,269.6		
	Upgrade DCS Controllers / Hardware		250.0	250.0		
	Water Treatment Plant - Acid/Caustic Tank Upgrades		200.0			
	Replace One of North or South Service Air Receivers Unit 3		308.0			
	Thermal In Service Failures		1,250.0			
2022	Upgrade On-Site & Access Roads			500.0		
	Refurbish Biogreen Waste System			100.0		
	Fire System Upgrades			275.0		
	Thermal In Service Failures			1,250.0		
	Light Oil System Inspection and Upgrade			100.0	900.0	
	Install New Lube Oil / Seal Oil Systems Unit 3 (Inc. Assessment of LO Program)			255.0	765.9	
	Overhaul Unit 3 - Generator Only			1,300.0		
	Upgrade 600V VFDs in Wastewater Treatment Plant			250.0		
	Replace existing Stage 1 4160 V AC Breakers as Required			750.0		
	Install Energy Efficient High Bay Lighting System			15.9	609.2	
	Units 3 Generator Upgrades - Slip Rings, Brush Gear, Bearings, Pony Motor and Starter, SSS Clutch, etc..			941.5	784.6	1,273.9
	Upgrade Protective Relaying - Unit 3 Generator (SEL)			500.0		
2023	Cooling Water Pumphouse Refurbishment (stop logs in yr.1, new removable screens, 60 hp pump/motor, Insp. CW				650.0	400.0
2024	Upgrade Ambient Monitoring Stations					250.0
	Water Treatment Plant Upgrades (if required for GSCW, Domestic)					1,000.0
		3,512.1	**19,929.6**	**8,807.0**	**3,709.7**	**2,923.9**
		2020 TOTAL	2021 TOTAL	2022 TOTAL	2023 TOTAL	2024 TOTAL

13.1.2 2019/2020 Capital Plan Supplemental Investments for March 2023 End of Normal Steam Generation

In November 2019 Holyrood Long Term Asset Management did a preliminary assessment of the capital requirements to extend the normal operating mode from the current March 31, 2021 to March 31, 2023. Table 13-1 below presents the capital listing resulting from that assessment. It identifies a number of required supplemental projects for 2019 through 2024.

Table 13-2
2019/2020 November 2019 Capital Supplemental Investments
for March 31, 2023 End of Normal Steam Generation

	Project	Estimate $	Year	Comments
1	API Life Extension Study – Fuel Oil Storage Tanks 3 and 4	$50,000	2019	Work planned for 2019. Tank 3 is currently good to March 2023. Tank 4 is currently good to November 2020. Need to determine if these tanks can be extended to 2023 or beyond.
2	API Internal Inspection and Refurbishment of Fuel Storage Tank 1	$4,000,000	2020	Required to use this tank beyond 2021. Hydro is currently attempting to extend this tank to 2023 through consultation with the appropriate government regulatory authorities and if successful then the $4m project will not be required. It may be possible to omit one tank inspection provided that Tank 4 is extended to 2023 and operation with three tanks is deemed acceptable for the final operating season.
3	API Internal Inspection and Refurbishment of Fuel Storage Tank 2	$4,200,000	2021	Required to use this tank beyond 2021. Hydro is currently attempting to extend this tank to 2023 through consultation with the appropriate government regulatory authorities and if successful then the $4m project will not be required. It may be possible to omit one tank inspection provided that Tank 4 is extended to 2023 and operation with three tanks is deemed acceptable for the final operating season.
4	API Internal Inspection and Refurbishment of Fuel Storage Tank #4	$4,000,000	2020	May not be required pending the results of the 2019 Life Extension Study (Item 1).
5	Refurbish Unit 3 Boiler Feed Pump West	$350,000	2019	Continuation of six-year overhaul frequency.
6	Refurbish Unit 3 Boiler Feed Pump East	$350,000	2020	Continuation of six-year overhaul frequency.
7	Overhaul Unit 2 Turbine Valves	$3,300,000	2020	Continuation of three-year overhaul frequency.
8	Overhaul Unit 2 Generator	$1,250,000	2020	Continuation of six-year overhaul frequency.
9	Major Overhaul Unit 1 Turbine	$6,800,000	2021	Continuation of nine-year overhaul frequency.
10	Condition Assessment and Miscellaneous Upgrades	$3,000,000	2020	Two-year extension to operate to 2023 would require two additional years of this project.
	(Boilers and High Energy Piping)			
11	Condition Assessment and Miscellaneous Upgrades	$3,000,000	2021	Year Two (see Item 10).
	(Boilers and High Energy Piping)			
12	Stack Inspection and Upgrades	$500,000	2024	Next three-year scheduled inspection date would be 2024. Need for this project depends on the decommissioning schedule. Stacks may be demolished before 2024.
13	Thermal In-Service Failures	$1,250,000 $1,250,000 $1,250,000	2021 2022 2023	Continuation of existing program.

The information was part of a package of information provided in November 2019 to the PUB.

Wood reviewed the capital listing in November 2019 based on its initial work on this study. Wood considered the Supplemental Capital identified by NLH as being both necessary and reasonable to the continued safe and reasonably reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023. Wood provided a Letter of Support. In most cases the funds requested allowed the continuation of many of the regularly scheduled major inspections and overhauls (consistent with Original Equipment Manufacturer guidelines) to ensure safe and reliable conditions for continued operation of HTGS. It was reasonable at the time that NLH identified some activities as conditional on the findings of prior investigative work, specifically as an example as it relates to detailed inspection and refurbishment of its primary oil tanks.

Issues expected to be addressed include items such as:

- It is expected that all regulatory and environmental inspections and overhauls will continue as required, although with some relief sought for the post March 2023 period where possible.

- Four main oil tanks will initially be retained (may require Tanks 1 and 2 be inspected and refurbished in 2020 to 2021) even into the start of the post March 2023 period. Consideration will be given in the period 2022 to 2024 to reducing the number to be retained to three.
- Plant heating solutions will be examined in 2020, including the use of the boiler #3 as an auxiliary steam source/thermal energy source.
- Non-regulatory inspections/overhaul intervals for the Steam turbine, steam turbine valves, boiler, generator (except generator #3) will in post 2022 period be extended to 10 years, five years, 5 years, and ten years or some form of usage-based system. Non-regulatory Intervals for other major equipment/systems will similarly be extended/managed.

In March 2020, Holyrood Long Term Asset Management revised its Supplemental Request to the PUB. The list of Capital projects currently included is shown below:

Description	Estimated Cost	Justification
Holyrood TGS Unit 1		
Internal boroscope inspection of Economizer Inlet Header including measurement of ligament cracks to track growth rate.	$37,500	Last inspected in 2017. B&W recommended re-inspection at three-year-intervals to monitor crack growth rate.
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Replacement of Sootblower 17R Aspirating Wallbox and Sleeve.	$22,000	Recommended based on condition assessed in 2019 when temporary repairs were performed to correct corrosion damage. Permanent repairs required to manage risk of sootblower impingement on wall tubes and jamming of moving parts on wall box if not replaced.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Replacement of the following three Down Comer Supports and leaking Header Expansion Joints: • 10th Floor - Cold Reheat Support, West Clamshell, "10B" • 10th Floor- Cold Reheat Support, East Clamshell, "10C" • 8th Floor- East MS, Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the following two observation ports: • 4th Floor - SW "A" Corner • 2nd Floor - SE "D" Corner	$96,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • Outlet Header • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Accelerateed Corrosion of Economiser inlet piping bends on the 6th Floor.	$12,000	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections. Projected wear rates determined from measurements made in 2017 indicate that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.

Description	Estimated Cost	Justification
Holyrood TGS Unit 2		
Measurement of Ligament Crack Growth by internal boroscope inspection on Economiser Inlet Header.	$37,500	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections indicating that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.
Condition Assessment of the East and West Air Heater Hoppers and Drains. Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless Steel.	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Header Expansion Joints: • 10th Floor CRH Support West Clamshell "10B" • 8th Floor West Hot Reheat (HRH) Header Clamshell • 8th Floor East MS Header Clamshell • 8th Floor West MS Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the 2nd Floor SW "A" Corner Observation Ports.	$82,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Condition Assessment of Forced Draft Fans.	$45,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • SH-1 Outlet Header 6th Floor West • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Accelerateed Corrosion of Economiser inlet piping bends on the 6th Floor at the North Side of the Boiler.	$12,000	Recommended by B&W at maximum 3.5 year intervals to minimise based on historic wear rates. Components were replaced in 2017 due to Flow Accelerated Corrosion.

Description	Estimated Cost	Justification
Holyrood TGS Unit 3		
Inspection of Boiler Feed Pump Piping Discharge Eccentric Reducer and "Y" for Flow Accelerated Corrosion.	$26,000	Recommended by B&W to prevent in-service failure based on maintenance experience at HTGS . The "Y" Was replaced in 2016 due to advanced Flow Accelerated Corrosion.
Inspection of Main Steam Turbine Terminal to monitor Creep & Thinning.	$32,500	Recommended by B&W at 3-year intervals based on findings of inspections completed in 2017 in which minor degredation and thinning were found.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Refurbishment of the 3rd Floor Southwest corner observation ports.	$82,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Investion of Windbox Corner Attachment failures including design and install of improved attachment method.	$45,000	Required to improve reliability of Windbox corner attachments which are prone to failure most recently causing a forced outage in 2018
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Condition Assessment of Forced Draft Fans.	$45,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$146,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Sampling and Analysis of Waterwall tubes including mechanical properties testing, deposition rate measurement and deposit chemical analysis.	$31,500	Recommended at three-year intervals by B&W to monitor deposit weight density and mechanical condition which will be used to inform chemical cleaning requirments.

Wood views these most recent Supplemental Capital items identified by NLH as a refinement of the earlier work and agrees that they are both necessary and reasonable to the continued safe and reasonably reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023. Wood provided a Letter of Support for the requested Supplemental Project list above. A copy of the Letter of Support is attached in Appendix A.

13.1.3 Capital Plan Suggestions for Reliable Generation by Units 1 to 3 up to the March 2023 End of Generation Life of Holyrood TGS

Wood also believes that modest investments in studies, engineering, moderate facility additions, and testing to facilitate/establish the potential opportunities for lower minimum load and faster starts are warranted in the 2020 to 2023 period, as well as for the post March 2023 cold standby/emergency mode of operation.

Quicker Start

Quicker starts will involve several aspects and steps to meet targets set, particularly for cold starts in post steam standby/emergency mode.

- Conversion of Unit 3 boiler to become the primary (but not exclusive) source of Auxiliary Steam (lowest cost initial option)
    - ✓ Design changes to provide mechanically atomized burners interchangeable with current burners
    - ✓ Operate at 1500-1600kPa continuously using Main Fuel Oil - use smaller burner nozzles on a number of guns which would be interchangeable for cleaning, temperature control. etc.
    - ✓ Modify Foxboro DCS logic (atomizing steam pressure required during normal generation, but not as an Auxiliary Boiler) - some minor logic changes to accommodate each mode of operation.
    - ✓ Use boiler feedwater pumps to supply feedwater at the lower boiler pressures (added maintenance on the BFW low flow control valves), but evaluate redesign of Reserve Feed Water System to supply each unit boiler with a higher pressure, flow controlled, supply of water
- Design and Implement Economizer Recirculation on Units 1 and Unit 2 Boilers
- Design and implement Steam Piping on Units 1 & 2 from the Auxiliary Steam Header to Turbine Gland Steam Systems
- Reinstall Boiler Furnace Cameras on Units 1,2 &3 and Provide Monitors in Control Room
- Install Motor Operators and Controls on Units 1 &2 Boiler Drum Continuous Blowdown Valves
- Install Motor Operators and Controls on Units 1,2,&3 Boiler Lower Waterwall Header Drains
- Implement procedures and training to utilize existing Boiler Temperature Probes on Units 1&2
- Design and Install Unitized Main Fuel Oil Unit Heating Recirculation from Suction Header to Recirc Line to Day Tank
- Design and Install Main Fuel Oil Storage Tank Recirculation on one or more main oil tanks
- Assess and if viable purchase a used simulator (2015 vintage) that appears to be largely compatible with HRD units and is currently available from OPG's Thunder Bay TGS (likely will not be on the market long)

A critical assumption is that regular inspection testing maintenance and PM's are maintained. It is also assumed that capital plans for 2020 and 2023 in Table 5-1 are implemented.

These could result in some economic relief and enhanced system responsiveness in the 2020 to 2023 period, as well as facilitate any longer-term standby operation if that were to prove desirable from a system flexibility and economic perspective.

Capital Program Suggestions identified in Chapters 8 to 11

The following is a summary of the Capital Program Suggestions identified in Chapters 8 to 11 addressing the high risk issues identified that are believed to be required for reliable generation by Units 1 to 3 up to the

March 2023 end of generation life of Holyrood TGS. Shorter term 2020 items are included in the updated Supplementary Capital request or within operating maintenance plans.

Table 13-1 Suggested Capital Plan Items – Units 1 to 3 up to the March 2023 End of Generation Life of Holyrood TGS

Section	Unit	Asset	Description	Timing	Priority
8.2.5.9 9.2.5.9	Unit 1, 2	271316 – Unit 1 Condenser 7664 – Unit 2 Condenser	Vacuum pump/motor replacements as PM's warrant.	2023-2025	3
8.2.5.9 9.2.5.9	Unit 1, 2	271316 – Unit 1 Condenser 7664 – Unit 2 Condenser	Condenser water box wall replacement – if Level 2 tests shown warranted.	2021-2025	2
	Unit 1, 2	Stack Coating	Recoat stack to reduce/eliminate moisture ingress through concrete and associated damage	2020-2023	1
8.2.8.9 9.2.8.9 10.2.8.9	Unit 1, 2, 3	6723 - Unit 1, 8152 - Unit 2, 8712 – Unit 3, Electrical and Control Systems (including DCS) Associated with Steam Systems	Continued critical control card spares procurement.	2020-2025	2
10.1.1.9	Unit 3	8298 – Unit 3 Generator	Stator Rewind in 2020-2022 period, if the unit is to operate as a synchronous condenser beyond 2021 to 2043	2020-2022	1
10.1.1.9	Unit 3	8298 – Unit 3 Generator	Refurbishment or replacement of the SSS clutch and motor (assess in 2021+ for 2023-2025 implementation as required).	2023-2025	1
10.2.10.9	Unit 3	271768 – Cooling Water System - Associated with Steam Systems	Upgrade of the wet well stop logs	2020	3
11.1.3.8	Common	6860 and 8730 – Common Electrical and Control Assets	Capital enhancements for elements of the breaker and motor control centres, particularly those that had a 2 to 5 year remaining life in 2010/11 and particularly if they are required for synchronous condensing option.	2020-2022	1

13.2 Capital Plan Suggestions for Unit 3 as a Synchronous Condenser – End of Generation Life of Holyrood TGS - Post March 31st, 2023

The following is a summary of the additional Capital Program Suggestions identified in Chapters 8 to 11 addressing the High Risk issues identified in 2010/11 Condition Assessment and 2017 update report and not yet addressed or any new High Risk Issues identified in 2019 that relate to the continued use of Unit 3 as a Synchronous Condenser beyond the March 2023 end of Generation Life for Holyrood – for 2043 Synchronous Generating Operation.

Table 13-2 Suggested Capital Plan Items – Unit 3 continues as Synchronous Condenser Post 2021 End of Generation Life of Holyrood TGS

Section	Unit	Asset	Description	Timing	Priority
10.1.1.9	Unit 3	8298 – Unit 3 Generator	Refurbishment or replacement of the SSS clutch and motor may be needed (assess in 2020/21 for 2021-2025 implementation).	2021-2025	1

Section	Unit	Asset	Description	Timing	Priority
10.1.3.9	Unit 3	8712 – Unit 3 Electrical & Control System Associated with Generators	Where a system is fully or partially required for synchronous condensing to 2043, consideration should be given in 2021-2030 period capital enhancements including: • Relay RM P&C 2019-2020 • Power Centre B 2019-2020 • MCC's 2019-2020 • UPS 2021 • Switchgear 2019-2020 • 250 V DC battery and chargers replaced – 2019/2020	2021-2025	1
10.1.4.9	Unit 3	271678 – Unit 3 Cooling Water Systems Associated with Generators	Level 2 assessment may conclude that the capital enhancements may be required related to items such as: • Refurbish Travelling screens • Replace auxiliary cooling water pumps and motors.	2021-2022	2
11.1.4.9	Unit 3	7283 – Main Powerhouse	Installation of auxiliary heating system – for building heating to avoid low load boiler operation for building heating only	2019-2020	1

wood.

14. Environmental/Regulatory Assessment Holyrood 2020-2027

14.1 Certificate of Approval/Operating Approvals

Below are the basics of the current 2018 operating approval for Holyrood TGS. It includes several amendments issued when the approval was first released in 2016, including the operation of the mobile diesels. Also attached is the approval for the API tank inspections to December 2021.

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Municipal Affairs and Environment

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***October 31, 2016*** Approval No. AA16-105640A

Amendment: ***April 2, 2018***

Expiration: ***August 31, 2021*** File No. 716.008, 716.050.1

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

TERMS AND CONDITIONS FOR APPROVAL No. AA16-105640A
April 2, 2018

General

1. This Certificate of Approval is for the operation of a 123 MW Combustion Turbine, Six (6) Diesel Generating Units and a Thermal Generating Station, including power house, wastewater treatment plant, hazardous waste landfill and associated works located at Holyrood, Newfoundland. Extensive future expansion or change of activities will require a separate Certificate of Approval.

2. Certificate of Approval AA16-105640 is revoked and replaced by this Certificate of Approval.

Expiration

108. This Certificate of Approval expires ***August 31, 2021.***

109. Should HYDRO wish to continue to operate the Thermal Generating Station and the Combustion Turbine beyond this expiry date, a written request shall be submitted to the Director for the renewal of this Approval. Such request shall be made prior to ***March 1, 2021.***

The details of the Certificate of Approval can be reviewed in Appendix B.

There was some concept of employing flue gas desulphurization (also known as "FGD" or "sulphur dioxide scrubbers") and particulate electrostatic precipitators ("ESP's") for HTGS if its life were significantly extended or additional capacity added. The suggestion was included in the GovNL 2007 Energy Plan (" 2007 Energy Plan: Focusing our Energy - basically to replace HTGS or to install scrubbers/precipitators. No requirement was ever formalized.

14.2 Greenhouse Gas (GHG) Commitment

Regulatory amendments are also likely required to address the continuation of HRD TGS in the light of current greenhouse gas (GHG) commitments and costs. The current regulatory framework is based on HRD TGS closure in 2021. Unless, current provisions are modified, the generation and use of GHG credits will involve a loss of revenue that will have to be accounted for. The issue of HRD TGS GHG targets themselves is an issue as they tighten with time.

15. Review of Human Resources/Staffing

15.1 Holyrood TGS Staffing to March 2023

Figure 15-1 illustrates the current staffing of the Holyrood TGS. There are approximately 101 staff positions (including 10 vacancies and 23 Term personnel). There are also at present 16 staff positions associated with the existing gas turbine or diesel facilities shown in Figure 15-2. These have in 2020 been re-assigned to be part of an overall Thermal Generation Division.

Wood's suggestion around a staffing plan for the period to March 2023 (or to whenever its normal steam generation role ends) would have no changes proposed until that date as the plant continues to operate in a manner similar to its current operation, but possibly even likely at a reduced level.

Wood does however recommend that Term positions be extended for a minimum two years through March 2022 to provide for some measure of continuity needed to manage plant safe operation. Further that Hydro should evaluate the advantages of some positions/Term staff becoming permanent employees.

Figure 15-1
Current Holyrood TGS Staffing – Similar for Period to End of Normal Steam Generation, March 2023

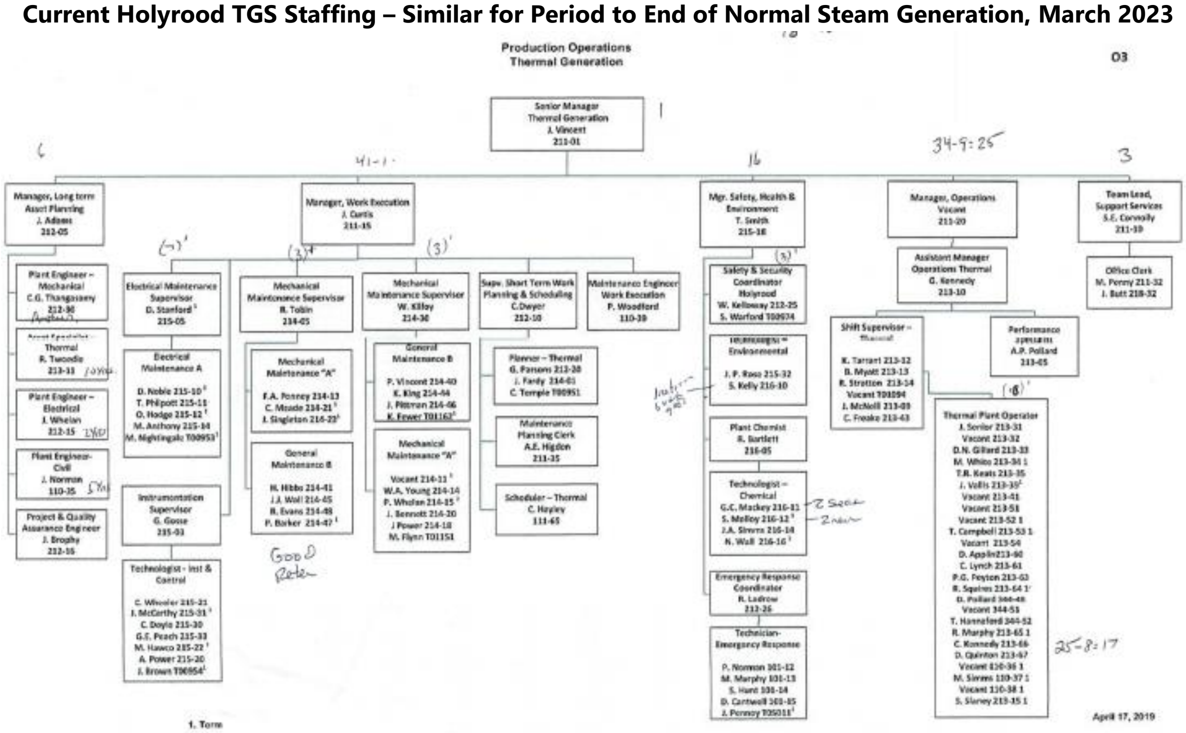
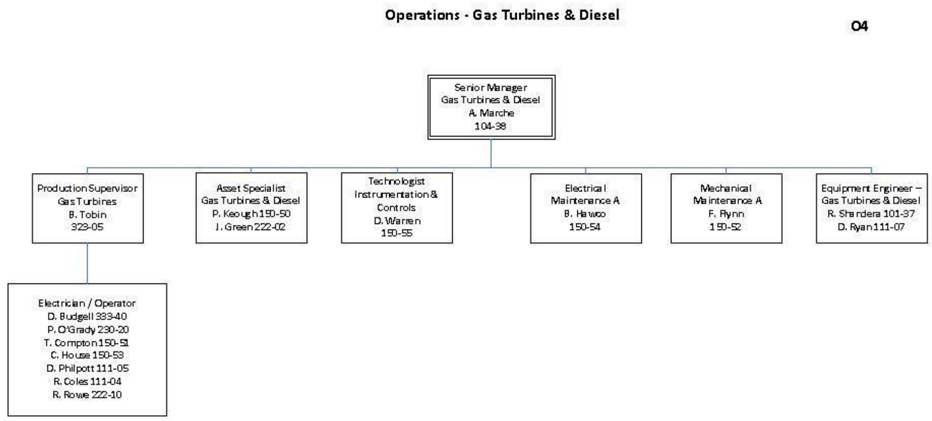


Figure 15-2
Current Staffing – Gas Turbines and Diesels



15.2 Staffing Model for Post March 2023 Cold Standby/Emergency Mode Period

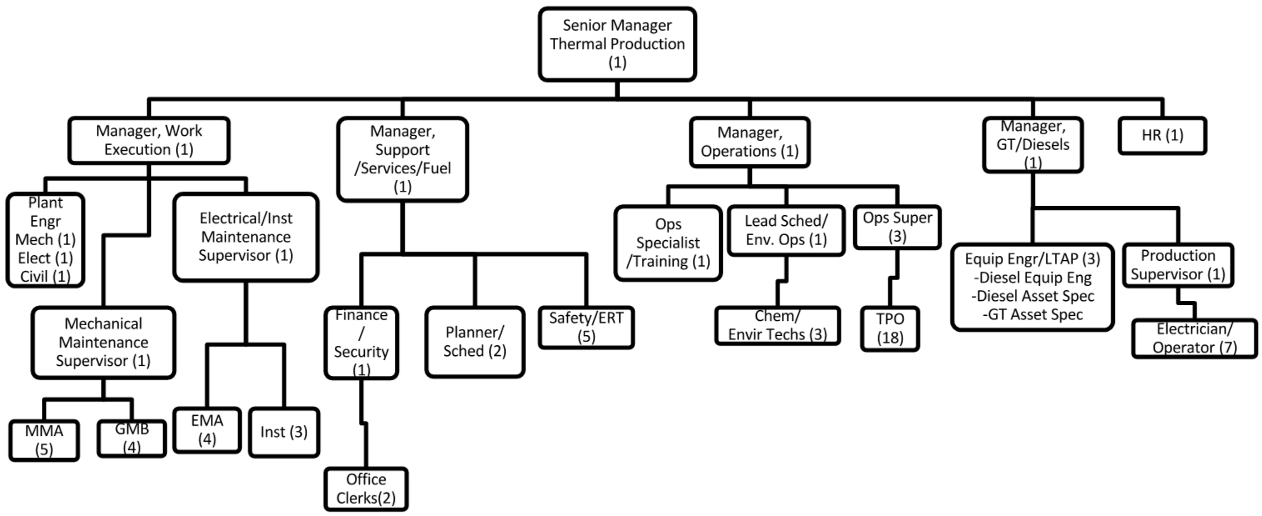
The current plan for post March 2023 (end of normal steam operation) assumes that all three HRD steam units be able to remain on cold standby/emergency operation mode after March 2023. It would require that all three HRD units be able to start up with 12 to 24 hours and run at full load on all three units for two to four weeks without staffing concerns. Unit 3 would operate in Synchronous Condensing mode unless needed for generation.

The key to staff planning in this period is to reduce numbers that would be required for normal standby operating mode of HRD TGS units, BUT maintain the flexibility in terms of numbers and skillsets to be able to start up within 12 to 24 hours and run at full load on all three units for two to four weeks without staffing concerns.

Wood suggests in Figure 15-3 a draft organizational plan for consideration and further development. It includes the Gas Turbine and Diesel staffing. It has about 74 total staff for the Thermal Division (62 HRD TGS plus 12 in the Gas Turbines and Diesels), down from current level of about 117 (101 at Holyrood TGS and 16 in the GT/diesel areas).

Wood considers Figure 15-3 as a good preliminary plan, as an input to overall planning for post-March 2023 periods.

Figure 15-3
Wood Staffing Suggestions Post March 2023



As noted, the Standby mode of operation is based on Units 1, 2 and 3 being able to operate possibly 2 to 4 weeks at any given time, with Unit 3 able to operate as either a Synchronous Condenser or as a Power generator if the situation warranted it. The other consideration is that each of the units be started up every three months in a "Fast Start" mode (preferably during the day shift) to exercise both the staff (to maintain staff skills) and the equipment (also identify any maintenance issues that require effort).

Based on the above criteria the staff plan in Figure 15-3 and detailed below was developed in order that Holyrood could be operated safely and reliably and be available to the NLSO within the given time frame of up to 8 hours for one unit and 24 hours for the second unit. The possibility of these times being improved upon was included in the planning process.

The purpose for listing the positions in the format below is to not only provide an explanation as to why they are required, but also the number in each.

Overall Management of Thermal Division

Senior Manager, Thermal Division (1) - There is no significant change proposed for this position. It remains necessary to provide overall direction and management to the activities of both the Holyrood station and the diesels and gas turbines in use throughout NLH.

- Human Resources (1) - The Human Resources resource will provide a critical function during what is likely to be a difficult period. The person will have to initially address corporate and staff needs during staff rightsizing, and once in Holyrood standby mode subsequently manage the processes to ensure that the Division as a whole maintains the right mix of competent staff to safely operate and maintain all of the various thermal generation facilities including Holyrood TGS.

Management Support/Services

Manager Support/Services (1) -This position is required to: a) provide leadership, direction, and support for all Support and Service employees; b) be directly responsible for managing the Safety/ERT Coordinator, the Planner/Scheduler, and the Finance/Security Lead, as well as unionized staff in excursion of assigned Job duties and responsibilities; c) administer the Collective Agreement and ensures supervisory staff are fully informed and are following the terms of the agreement; d) prepare, administer and manage the department budget to maintain expenditures within approvals and provided explanation of variances and obtained approvals for overruns; and e) Manage and coordinate fuel contracts requirements for delivery as well as all Outside Contracts and Contractors. Other responsibilities associated with the position and group include:

- Safety Health and Emergency Response: a)promote and ensure compliance with the Safety Management System, and ensure the maintenance and development of the required standards, policies and procedures; b) promote and ensure compliance with other Corporate policies related to safety; c) assist in the identification of high risk activities, and ensuring that the appropriate work methods and/or procedures for mitigating the risk are developed, implemented and maintained; c) Contractor Safety Management: ensuring that approved safety plans are in place and contractor reporting; e) assist in the completion of Incident and Near Miss Investigations and ensuring that remedial/corrective/preventative actions are implemented where required; f) ensuring Safety Culture Action plan is developed, maintained and effective; g) ensure that the Industrial Hygiene program is monitored - would include air quality monitoring, noise monitoring. g)ensure that the Emergency Response Plan is implemented, maintained and updated when required; h) ensure that the Emergency Response manual is maintained and updated when required; i) support and promote Corporate Policies related to Emergency Response, Fire Protections and Safety; and j) ensure that Emergency response is in compliance with FM Global.

- Environment – Regulatory Requirements Management: a) ensure that the Environmental Management System (EMS) is maintained in accordance with ISO 14001; b) work to ensure that Document Control and record management systems satisfy the requirements of ISO 14001; c) ensure Regulatory Compliance according to HTGS Certificate of Approval (COA) for Provincial government reporting (environmental compliance monitoring ,sampling information and reporting); and d) ensure compliance for Federal governing reporting with the completion of the National Pollutant Release Inventory (NPRI).

The importance given the reduced overall staff, the complexities of Thermal generation facilities generally and the criticality of the right planning/scheduling and fuel management activities during this time period cannot be overemphasized.

- Safety/ERT Coordinator (1) - The Safety and ERT Coordinators positions will be combined. The job function would include all safety training and orientation provided to all station staff and any contracted staff visiting or working on Thermal Division sites. Safety and emergency response become particularly important as the experience of staff likely are reduced over time. The usefulness in assisting other parts of the company, as is currently being offered will continue to be helpful as well.
  - ERT Techs (4) - Emergency Response Techs are required to ensure all safety related PM's are being completed and that all safety related equipment is in good operating condition. They are required to maintain a) Fire Protection and Life Safety System Preventative Maintenance; b) Safety Program and Emergency Response Training and Program Management; and c)

Emergency Response and Stand-By Rescue (Confined Space/High Angle).It is anticipated that the staff may also provide some other roles within both the Division and within Holyrood as the needs become clearer over time.

- Planner/Scheduler (1) - Day to day work activities for the station's maintenance sections will continue to be required to ensure the plant is available when required and to address ongoing regulatory and condition assessment work going forward. The planner will work in conjunction with one of the office's clerical staff to ensure that the work plans are developed and ensure the resources are available in order that the work can be carried out.
- -Finance/Security Team Lead (1) - The Team Lead for Finance/Security will ensure that all issues relating to either Finance or Security within the Division are addressed appropriately. This position also will provide supervision for the office clerks one of whom will be working with the Planner/Scheduler.
  - Office Clerks (2) - Two are required for documentation control and payroll inputting as well as assisting the Planner/Scheduler

Work Execution

Work Execution Manager (1) -The Work Execution Manager is required to direct and manage both the station engineering staff as well as the Maintenance Section staff. The role is responsible for one of the larger labour groups in the station. The biggest change for the role recognizing the standby nature of the Holyrood station is the inclusion of the engineering function as well as the mechanical and electrical and instrumentation maintenance supervisory functions.

- Mechanical Engineer (1) - The position is responsible for all Mechanical Engineering issues as related to the overall operation of Holyrood. Some of these issues relate to but are not exclusive includes all boiler/turbine generator/ common services including fuel supply, service water, air compressors, combined generator oil and gas systems and any other system with a mechanical component within the plant, as well as support to other Divisional facilities.
- Electrical Engineer (1) - This position is responsible for all Electrical Engineering issues as related to the overall operation of Holyrood, as well as support to other Divisional facilities. Some of these issues relate to but are not exclusive including all electrical and control items with respect to the boiler/turbine generator including the excitation system / common services / electrical switchgear / plant lighting inside and outside / relaying changes and any other system with an electrical component.
- Civil Engineer (1) - This position is responsible for all Civil Engineering that pertains to the powerhouse, administration building any other outside buildings including the marine terminal, training center, warehouse building, fuel oil storage tanks, waste water lagoons, any other containment dykes are reliable. Ensure that all Government Regulations as to tank inspections, stack inspections and stack lighting are adhered to, as well as support to other Divisional facilities.
- Mechanical Maintenance Supervisor (1) - This position would be responsible for the supervision and guidance of both the MMA's and the GMB's to ensure the day to day work is carried out safely and correctly and that equipment is available to operate as needed. Combining these two groups will allow for a complete knowledge of what work is being performed on a daily basis (PM's, CM's, as found work, equipment testing and exercising) to ensure the plant can respond to NLSO requirements.
  - MMA's (5) - Including at least one high pressure welder with the rest being millwrights to round out the complement.

- GMB's (4) - Four are required, one of whom should be a carpenter. Building of scaffolding and safety systems such as protective barriers around openings. When not doing those duties helping the MMA's should be included in their job description.
- Electrical/Instrumentation Supervisor (1) - This position would be responsible for both the EMA's and the Instrumentation Technicians ensuring the day to day activities (PM's, CM's, as found work, equipment testing and exercising) are being carried safely and efficiently and the plants electrical and instrumentation devices are in good working order when the plant is either shutdown, in synchronous condensing operation, or is required to operate in generation mode.
  - EMA's (4) - Four will be required to provide support for the safe efficient operation of the plant. Staff will be required to step up into the supervisor's position as needed.
  - Instrumentation Technicians (3) - Three will be required to ensure the control systems and relaying is in good working order. Staff will also be required to step up into the supervisor's position as needed.
  - (Note: At some point combining the EMA and Instrument Tech positions should be reviewed.)

Holyrood TGS Thermal Operations

Operations Manager (1) - Presently the Operations Manager is also the Chief Power Engineer for the plant. This position would be required to ensure the safe and proper operation of the thermal facilities, including the provision of appropriately trained operating staff/teams. This position does not necessarily hold the Chief Power Engineers certification, as someone else may be designated as the Chief Power Engineer as long they possess a 1st Class Power Engineering Certificate from the Government of Newfoundland and Labrador. The Operations Manager will assist the Senior Manager, Thermal Operations when requested while ensuring the safe reliable operation of the plant in cooperation with the Operations Supervisor who could be the Chief Engineer under this plan.

- Chief Power Engineer/Operations Supervisor (1) - If the Operations Manager is not the Chief Engineer, then a new position would be created in order for the Government Regulator to have a contact in case the plant is in contravention with the Regulations. This position would ensure that qualified Power Engineers were operating the units at all times. The person would hold a 1st Class Certification in the Province of Newfoundland and be totally knowledgeable about the operation of Holyrood and would be responsible to the regulator in the Province of Newfoundland and Labrador at all times with respect to the safe operation of the plant. Previous staff plans have shown the Operations Manager as being the Chief Power Engineer and if that remains then the Chief Power Engineers position would instead be an Operations Supervisor with responsibility for scheduling operations staff while remaining as the supervisor for the Chemical / Environmental Technicians.
  - Chemical/Environmental Technicians (3) - These positions would report to the Chief Power Engineer/Operations Supervisor listed above and would be responsible for operating the plants Water Treatment System, while doing boiler chemical analysis, chemical injection, monitoring the Continuous Emissions Monitoring System and doing off site environmental monitoring as required. This list of duties will be examined and may be modified to include other duties as required.
- Operations Specialist/Team Lead (1) - This position would be responsible for Operations Training and would provide scheduling for the Thermal Plant Operators and the Operations Supervisors. The Operations Specialist would also be required to fill in on shift as required when the units operate or for vacation relief and other time off as required and may be needed as an Operations Supervisor if the situation is warranted.

- Operations Supervisors (3) - Three experienced Operations Supervisors will be required. They will provide shift coverage 24 hours per day, 7 days per week, 52 weeks per year, in spite of the generation function of the plant being on cold standby. They are absolutely to ensure the capability necessary to provide the 2 to 4 weeks of continuous emergency operation as/when it occurs. Also, there remains the need to provide auxiliary steam (possibly firing Unit 3 as an auxiliary boiler, or having a higher pressure auxiliary boiler) and operating the #3 generator as a synchronous condenser and with operations staff levels reduced during those time frames. They are also to maintain contact with the NLSO and call in staff as required to start up Units 1&2 if the fast start situation arises. Likewise, if the conversion of unit 3 back to the power generation mode is required calling in of Maintenance Staff and ensuring that function is done in a timely manner while supervising the Thermal Plant Operators required on shift when the plant is not generating power is also their responsibility.
  - Thermal Plant Operators (18) - Eighteen experienced operators will be needed to be able to operate the plant 24/7 for 2 to 4 weeks in the event of an emergency, as well as during equipment/staff exercising periods. They will be required to do Operator related PM's and any other duties as required such as maintaining the shutdown units in a state of readiness in case the NLSO requires a unit quickly or exercise run setup. When the station is not generating power at least 3 TPO's may likely be required on shift 24/7 to provide the coverage needed to provide necessary auxiliary steam (operate unit 3 as an auxiliary boiler or a higher pressure auxiliary boiler), and the unit 3 generator as a Synchronous Condenser. They will also maintain other common auxiliaries in the station and out in the tank farm area. Their duties will include cleaning oil guns, preparing, hanging, verifying, and issuing Work Protection along with performing system tests on PC14's and PC10's. The remaining TPO's will be rotated onto shifts and will also be required to fill in for relief when needed. Primarily during the day shift periods, operators may be used to do non-union certified jobs like help MMA's, GMB'S, etc. and also take part in Training Sessions to maintain and sharpen the skills needed to operate a large Thermal Generating Station.

Gas Turbine/Diesel Plant Facilities

Manager, GT/Diesels (1) - This represents a shift from management of the diesel facilities and gas turbines to a common division. The Manager GT/Diesel position brings a dedicated view to all aspects of the work of these diverse facilities (capital planning and maintenance and operation) within the context of the overall Thermal Division.

- Engineering/LTAP (3) - There are three distinct positions: Diesel Equipment Engineering, Diesel Asset Specialist and GT Asset Specialist. They represent the specialist knowledge that previously resided in TRO and Rural generation that was necessary to maintain, and capital plan these diverse assets. The need for these roles has not changed as a result of the changes in Holyrood TGS.
- Production Supervisor (1) - This position will co-ordinate the overall production planning and implementation of operations at all Hydro's diesel and GT facilities, managing and directing the 7 operators required. This consolidates the similar aspects formerly in TRO and rural generation.
  - Operators (7) - These positions represent the current operators in the field performing local operation and non-critical maintenance. The need for these roles has not changed as a result of the changes in Holyrood TGS.

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Table 15-1 provides a summary preliminary rationale for the changes between the pre and post steam (March 2022/23 periods.

Table 15-1
Rationale for Changes Between Pre-March 2023 and Post March 2023 Organizations

Holyrood Staffing 2020--2027+	(Excluding diesel/GT staffing)	
Woods HRD TGS Staffing Plan 2020-2023 Plant operates similar to 2019 2020 to March 2022 or 2023	**Woods Staffing Plan Post Steam Holyrood Emergency Mode 2-4 week All Units at Load U3 Synch Condenser Mode Post Steam (March 2022 or 2023)**	**Summary Rationale for Changes**
Senior Manager Thermal Operations (1)	Senior Manager Thermal Operations (1)	No change - duties continue. Managing and directing reduced HRD TGS staffing, but also all diesels and GT's; liason with Corporate and NLSO
Long Term Asset Planning Manager (1) Work Execution Manager (1) Short Term Work Planning &Scheduling Supervisor (1)	Manager, Work Execution (1)	Given new role and reduced generation timeframe, combined Work Execution and LTAP Planning Mgr. and Short Term Work Planning into one. Added duties wrt day to day planning/scheduling/contracts, and undertaken by adding Engineering disciplines in this group.
Asset SpecialistThermal (1)	(Not Required)	Combined within Manager, Work Execution and undertaken by maintaining Engineering disciplines in this group.
Project & Quality Assurance Engineer (1)	(Not Required)	Combined within Manager, Work Execution and undertaken by maintaining Engineering disciplines in this group.
Plant Engineer Mechanical (1)	Plant Engineer Mechanical (1)	Moved to Work Execution. Requirements remain, but more focused/involved in daily activities while also managing contracts, assets management and project/quality control aspects.
Plant Engineer Electrical (1)	Plant Engineer Electrical (1)	
Plant Engineer Civil (1)	Plant Engineer Civil (1)	
Mechanical Maintenance A Supervisor (1)	Mechanical Supervisor (1)	Combines Mech Sup (A) and Gen Mtce Supv (B) under 1 supervisor
Mechanical Maintenance A (9)	Mechanical Maintainers A (5)	Reduced work due to mode change.
Mechanical Maintenance B Supervisor (1)	(Not Required).	Combined under Mechanical Supervisor
General Maintenance B (8)	General Maintainers (4)	Reduced work due to mode change.
Electrical Maintenance Supervisor (1)	Electrical Instrumentation Mtce Supv (1)	Combines Elect Mtce Sup and Instrum Mtce Supv under 1 supervisor
Electrical Maintenance A (5)	Electrical Maintenance A (4)	Reduced work due to mode change.
Instrumentation Supervisor (1)	(Not Required)	Combined under Electrical Instrumentation Mtce Supervisor
Instrument& Control Techs (7)	Instrumentation Control Techs (3)	Reduced work due to mode change.
Maintenance Engineer, Work Execution(1)	Not Required	Role covered by Plant Engineer Mechanical and Mtce Supervisor
Short Term Work Plan, Sched, Exec - Planner-Thermal (3) - Maintenance Planning Clerk (1) - Scheduler-Thermal (1)	Not Required.	Role moved to Work Execution due to reduced work overall for short and long term - consolidation of roles/work.

There are however many possible variations that should be considered in determining final numbers and the final organizational pattern for the post March 2023 period. It remains critical to remember that the pattern must address the emergency operational needs (2 to 4 weeks at full load).

16. Quicker Start Plans/Requirements

Wood was asked to look at a high level at the potential for and requirements for implementing quicker starts at HRD TGS.

Wood considers that the pre-March 2023 criteria of 4 to 8 hours recall from hot standby can be achieved without major modifications to the plant equipment. Nevertheless, Wood considers that 2020 to 2023 is the time to engineer, test, and implement modifications for quicker start and lower loads for both the pre-March 2023 period, as well as for the cold standby/emergency mode period post March 2023

After extensive discussion with Operations and Maintenance Staff at Holyrood, Wood believes that all units at Holyrood can be started up much faster than historically typical. Reaching the time criteria as laid out in the "2019 Holyrood Thermal Generating Station Condition Assessment Update Study" of 8-12 hours for one unit and up to 24 hours for the second unit is achievable.

A number of changes need to be made in order for that to happen and are required during the time frame of 2020-2023 to prove their viability.

- First, there are changes required in mechanical design and installation
- Second, a mindset change within NLSO and Holyrood has to be established due to the new role in which Holyrood will be operated.
- Third, providing updated training facilities to keep operating staff skill levels current including actual test starts in 2020 to provide confidence that these goals are achievable into the future.

16.1 Mechanical Changes Required:

The following is a listing of the mechanical changes required in order of Priority:

16.1.1 Convert Unit 3 boiler to become the primary but not exclusive source of Auxiliary Steam.

When a Holyrood unit is being requested now by the NLSO and all Holyrood units are out of service it takes Operations ten plus hours firing the boiler on the unit being requested using expensive #2 Ignition Oil to raise the boiler pressure enough to charge the auxiliary steam header. Auxiliary Steam is needed in order to supply heat to the Main Fuel Oil Storage Tanks, the Main Fuel Oil Day Tank, the main fuel oil lines heat tracing, provide atomizing steam pressure for the unit main oil burner operating limits, and heating the main fuel oil heaters on the individual unit by raising the Main Oil temperature to the limit acceptable for combustion before ever firing one Main Fuel Oil burner. Then and only then can the operators proceed with the start-up.

The station requires Auxiliary Steam for all the systems listed above as well as in-plant heating when sitting in Standby. Even though the units may not be required to generate power, maintaining temperatures in the Main Fuel Oil Storage and Day Tanks and Main Oil line heat tracing is required in order for the oil to flow when the outside temperatures drops below 10C – 15C can occur sometimes as many as nine months of the year. Presently at least one unit is in service 24/7 during the above time frame and auxiliary steam is supplied from that unit running at a very high minimum load.

Converting Unit 3 to becoming the source of auxiliary steam when the plant is in the standby position is a viable option for a number of reasons.

- First, Unit 3 generator is going to be primarily used as a synchronous condenser and therefore not required as a generation source during those times. With Unit 3 in service as an auxiliary steam source and burning Main Fuel Oil, heating of the Main Fuel Oil suction line to the other two units will naturally occur because as main fuel oil is being used on U3 some of the oil will be recirculating back to the Day Tank and with #3 at the furthest point on the suction header, temperatures will be available to fire main fuel oil on U1 and U2 almost immediately after the call to start a unit is received from the NLSO.
- Second, presently U3 drum level control is more easily controlled because U3 boiler is equipped with an Economizer Recirculation line which prevents the economizer from being boiled out when there is no demand for feedwater. U1&U2 at present do not have economizer recirculation capability and drum level is extremely difficult to control. When either of these two units are started now the water level in the drum rises due to the swell created by heating and because the drum level setpoint is exceeded feedwater flow is stopped and the economizer continues to steam and empty itself into the drum which may cause a nuisance "high drum level" boiler trip if the operators are not quick enough to manually drain water from the boiler. Once the drum level decreases the boiler feed system must first fill the economizer with cold water before any is seen in the drum at which time the boiler will sometimes trip on low level depending on how fast water is added. During this filling, the economizer tubes and headers are being thermally stressed with cold water being added to hot metal causing cracks in the tubes and headers.

The conversion of unit 3 would require testing in 2020/21 to prove it workable.

- Design changes would be needed to provide mechanically atomized burners that would be interchangeable with the burners now being used so if the need arose to use U3 as a power generator it can be.
- Unit 3 would require to be operated at approximately 1500-1600kPa continuously using Main Fuel Oil which necessitates the using of smaller burner nozzles on a number of guns which would be interchangeable for cleaning, temperature control. etc.
- Burner oil pressure is controllable on U3 at each burner using the DCS controls in the Control Room whereas units 1&2 have one pressure control valve for the entire burner system and is very difficult to control if only one or two burners are is in service. Therefore Unit 3 offers better control of the boiler overall whereas on the other Units the operators have to go out and manually throttle valves to achieve some sort of control.
- The Foxboro DCS logic where the atomizing steam pressure is a requirement during normal generation mode would not be required as an Auxiliary Boiler and some minor logic changes are needed to accommodate each mode of operation.
- Issues like using the boiler feedwater pumps to supply feedwater at the lower boiler pressures would create a lot of added maintenance on the BFW low flow control valves and although this system can be used now a recommendation to redesign the Reserve Feed Water System to supply each unit boiler with a higher pressure, flow controlled, supply of water should be examined.

The initial costs to modify U3 to become the auxiliary boiler would likely be moderate in comparison to renting a package boiler or purchasing and installing an auxiliary boiler while ensuring the unit would be available as a power generator if required.

16.1.2 Design and Install Economizer Recirculation on Units 1 and Unit 2 Boilers

The benefits of having Economizer Recirculation on these two boilers were discussed in 16.1.1 above. This modification was recommended to be installed a number of years ago by Holyrood staff. At that time, a determination was made and seen to be unnecessary when Holyrood was a base loaded plant with very few starts required. However, for a standby mode and a need for fast starts, it is requirement in order to provide the flexibility of the units to the NLSO. Having the economizer recirculation will make it easier to control drum levels on starts and should reduce the number of repairs of economizer tubes as an added benefit.

16.1.3 Install Motor Operators and Controls on Units 1, 2, & 3 Boiler Lower Waterwall Header Drains

In order to control boiler drum levels on start up at present, operators have to quickly send someone down to the ground floor and open the lower waterwall header drains manually. Drum level swells occur a number of times during the early stages of start-up causing high drum level trips of the boiler which then creates the need to purge the boiler of combustible gases and restart the burners. All of this adds a great deal of time to the start. Adding motors on these valves is not difficult or time consuming, but care must be exercised as to when these valves are allowed to be open. Logic would have to be added to the controls in the DCS that would prevent the valves from being opened once the steam pressure in the boiler drum reaches 3000kPa. These motor operated valves and controls would need to be added in 2020 and from all indications in the plant that would be doable.

16.1.4 Install Motor Operators and Controls on Units 1 &2 Boiler Drum Continuous Blowdown Valves.

Presently Unit 3 has a motor operated Continuous Blowdown valve, however the controls are local to the valve which then requires an operator to go up on the boiler to open this valve if the drum continues to rise for any number of reasons. Drum level swells will occur above the 3000kPa plateau that the OEM has set for using the Lower Waterwall Header Drains by just firing additional burners in the furnace to raise pressure or if the Boiler Feed water system control valves pass when they are closed fully.

Units 1&2 are manually operated valves at present; therefore, the operator must be dispatched to the valves near the top of the boiler and then wait until the order to close the valve is received. These valves need to be motorized in order to reduce spurious high drum level trips which occur presently and the recommendation here is that the controls to operate the motorized CBD on unit 3 be brought back into the Control Room and motor operators be installed on Units 1&2 and the controls also brought into the Control Room. There is no DCS logic required as these valves can be opened at any pressure when the boiler is operation. These motor operated valves and controls also need to be added in 2020 and because Unit 3 is already been done at least partially completing the project is seen as doable.

16.1.5 Steam Piping on Units 1 & 2 from the Auxiliary Steam Header to Turbine Gland Steam Systems.

Unit 3 currently has this connection, but Units 1&2 are not connected. Using the Auxiliary Steam to preheat the turbines when they are shut down and gland steam is not available from the unit boiler is an option that has been used by power companies in North America to keep the turbines warm. Steam enters the turbine glands and using the condenser vacuum pump to create a slight vacuum a flow of saturated steam at 100ºC is passed through the HP, IP, and LP turbines in order to heat soak the turbine metals. Once the piping is installed on Units 1&2 testing of the system would be recommended.

16.1.6 Reinstall Boiler Furnace Cameras on Units 1,2 &3 and Provide Monitors in Control Room.

High definition cameras are now available to allow the Control Room Operators to see the boiler flames and adjust firing parameters accordingly, in order to provide the cleanest environment at the outlet of the stacks. All of the requirements are on the boilers as cameras were used in years past, but then removed. (pictures hanging in the Admin building of the control room in earlier times actually show the monitors with flame present).

Purchasing new HD cameras and monitors and installing them in the ports already provided will let the operators determine which burner is creating opacity issues and be able to have the burner removed from service for repair much faster than the trial and error method they must use now.

16.1.7 Boiler Temperature Probes on Units 1&2 Need to be Utilized.

Unit 1&2 are already equipped with boiler temperature probes; however they have not been used for at least 30 years. Starting a Holyrood boiler quickly was a major concern because of their seasonal base load operation. Aggressively firing the boiler was not a major concern, along with the need for constant repair. These probes were deemed to not be required. Nevertheless, the boiler temperature probes were installed to protect the reheater section of the boiler, which has no flow until after establishing a steam flow through the HP turbine which only occurs during the roll to synchronous speed. There are now today newer technologies which have been developed and the installation of these optical digital temperature measuring devices are recommended so the operators can aggressively fire the boiler and start the unit up faster than previously required, and still prevent damage to the reheat sections of the boiler.

16.1.8 Design and Install Unitized Main Fuel Oil Heating Recirculation from Suction Header to Recirc Line.

Units 1, 2,& 3 require the capability of being able to heat and recirculate Main Fuel Oil back to the Main Fuel Oil Day tank, especially when Unit 3 is not required as an auxiliary boiler and the other two units are in standby. Maintaining the day tank temperatures at or close to the temperature required for combustion is a must in order to be able to fire main fuel and raise boiler pressure quickly. The equipment necessary to make this happen would be an electric heater, a small forwarding pump with a suction strainer, and some piping with valving to be able to recirculate the oil back to the Day Tank from the Main Oil Supply Header back through the recirculation line. It may be possible to use the area where the former Auxiliary Boiler was located. Further investigation in regards this location would be required. Presently the Main Fuel oil to the units is gravity fed therefore a mechanical method to recirculate the oil is required.

16.1.9 Design and Install Main Fuel Oil Storage Tank Recirculation.

Given the long periods of standby operation, it is highly desirable that the Main Fuel Oil Storage Tanks have a mechanical method of Recirculation within themselves on whichever tanks are chosen to stay in service during the standby mode of operation.

Presently the only method of heating the Main Fuel Oil in the Storage tanks is to apply steam to the Storage tank Suction heaters which are located at the bottom of each tank. Therefore, only the bottom of the tank is heated, which allows the oil to move by gravity to the Main Oil Day Tank. Initially steam supplied platform heaters were available approximately one half the way up each of the tanks, but these were taken out of service and then physically removed due to leakage problems.

The current issue is that the main fuel oil at the top, middle and some part of the lower portion of the tanks cool and the heavy deposits drop to the bottom of these tanks and either collects below the suction heaters in the tank and the outlets to the day tank or it remains in suspension long enough to get carried over to the unit suction strainers and fuel oil heaters (because the day tanks have recirculation from the units which allows the solids to remain in suspension until it collects at the unit).

Installing a recirculation system from the bottom of the Main Fuel Oil Storage tank to the top would bring the overall tank temperature closer to the temperature created at the suction heater. It would aid in keeping the suspended solids in suspension and limiting the deposits to form or collect in the unit strainers. Providing a centrifuge in the recirculation system would also be useful in removing the solid deposits in the oil. The unit oil strainers are isolatable to allow cleaning during unit operation. However, the unit fuel oil heaters must be physically taken apart for cleaning when they foul. Photographs of the unit fuel oil heaters were taken by Holyrood staff and the sludge buildup is excessive and the cleaning is very time consuming. It takes a number of personnel committed to complete the job preventing them from doing other tasks.
Reducing the sludge would prevent the damage now being observed in many portions of the Main Fuel Oil System.

16.2 The Mindset Change at NLSO and at Holyrood:

The NLSO and Holyrood staff have developed over the many years of seasonal base load operation a perception and a mindset that Holyrood Units require in some cases days to start up a unit.

Possibly this developed due to Holyrood's inability to have auxiliary steam available if all the units were shutdown, or possibly just the result of how outages were typically arranged and administered. This perception does seem to result in costly starts and has likely kept Holyrood units in service at high minimum loads while spilling water at hydroelectric stations during low system demand.

It is Wood's contention that this long historical mode of operation has limited the understanding of the role that Holyrood is capable of providing. As an option for the future, whether in a hot standby or a cold standby/emergency role, the mindset now needs to be changed - a more aggressive approach is needed for Holyrood to be a viable alternative to the NLSO and the Newfoundland Grid.
To accomplish the change a number of different tests are being recommended as part of a planned extended study scope in order to prove the plants capability.

- The first set of tests require Units 1&2 in 2020 to be in a cold ambient condition on both the boiler and turbines with the availability of auxiliary steam from U3 to all of the systems needed to start a unit. The cold start tests need to be done a number of times in order to document the procedures needed to accomplish the task in order for all staff (NLSO and Holyrood) to understand what is required while establishing a confidence that this can be done in a minimum amount of time.
- The second set of tests recommended is to run the units at a much lower minimum load than the present 70 MW's per unit (which when all three units are in service is 210 MW's) Due to a number of factors involved in running the units at these lower loads, it is suggested that a series of tests be conducted at different loads to determine which load is best suited to the Holyrood units.
- The third set of tests (although not required as part of this study) would be the availability of these units to be two shifted. Many power companies in North America have gone to two shifting on their fossil fired plants and Holyrood is capable of being two shifted, but again procedures have to be developed. Having some maintenance support on shift during those times is also a requirement to help ensure the starts are successful. Certainly, there are risks associated with two shifting and they

have to be evaluated, but this provides an alternative to the NLSO in how the Grid is operated and the economic spinoff that would be realized.

16.3 Operator Training

In its historical role, there have been sufficient opportunities for regular operator training and skills development. With a shift in role to a standby/emergency mode role, another mindset shift is felt necessary. While some equipment and operator training «exercising » has been suggested (about 6 starts and stops with 2 days of running each) to help keep operators sharper and identify equipment issues during non-critical times, it is likely not enough to adequately keep operators sharp and/or train new operators for the new role of being in Standby. When Holyrood is in its Standby Mode of operation and not running the operators like any profession that does repetitive skills will tend to lose the sharpness required to perform the operations needed when the situation arises.

- Providing an operator simulator needs to be evaluated again or risk not having a Holyrood unit when needed. Presently Holyrood Operators have a minimum of experienced people and with the impending retirement or the changing of employers for some, that experience level will drop even further. Having the simulator to practice on and to learn what to do when something does happen on a running unit is paramount. This recommendation is not as critical the way Holyrood is being operated today. It will become critical when the plant is considered to be in Standby. Being proactive now rather than reactive later will provide time to purchase and engineer the equipment and to do it right.
- A used simulator (2015 vintage) that appears to be largely compatible with HRD units is currently available from OPG's Thunder bay TGS, but likely will not be on the market long.

At the present time none of the above recommendations include what might be done to aid in starting up the turbines without going through the present day, HP turbine prewarm. All of the steps above except the use of auxiliary steam to the turbine gland steam to preheat the turbine relate specifically to the boilers. By implementing these changes the units will be capable of starting using the criteria supplied however we are examining other methods of preheating the HP and IP turbines using a different source of heat which will reduce the start times and even lower the times significantly and we will make recommendations when they become available.

All of these recommendations will in fact allow Holyrood to be started faster and more economically, which will very likely make the station a more viable resource to the Newfoundland and Labrador Hydro and the people of Newfoundland.

17. Reduced Minimum Load

Wood believes that lower Minimum Loads on all Holyrood units should be achievable, likely from current 70 MW levels to on the order of 30 to 40 MW per unit. OPG's oil dual fueled Lennox 500 MW units were and are typically operated as low as 35 MW.

In the past there was no apparent driver corporately applied to push this given the typical load requirement pattern required by the system – generation from March to November from one to three units at 100 to 150 MW during the peak daytime periods and minimum 70 MW at night – ideal from a life management and reliability perspective.

Lower minimum load operation has several potential aspects to consider:

- Provides source of significant spinning reserve if needed
- Provides source of auxiliary steam for faster starting other units and fuel heating
- May be able to provide significant MVAR capability at low loads if required
- Could provide for enhanced hydraulic storage/sale of hydro energy in peak periods offshore
- Allows for fuel rotation in storage, less degradation

It does of course have drawbacks:

- Fuel cost if capacity/energy not required
- Adjustments in settings and control require testing to establish level and confidence
- Additional operation results in possibility of additional maintenance

There really is only one "option" if lower minimum loads are required or desired, which is to focus on operational practices, ensuring settings and operational procedures are suitably and safely adjusted. The steps are:

- Test plan – development and communication/agreement with plant staff and NLSO
- Testing – including interim settings and logic changes to allow lower load
- Procedure documentation
- Communication – Operations and plant staff and NLSO

18. Improving Unit 3 Changeover To/From Synchronous Condenser to a Power Generator

An onsite review of means of improving the time it takes Holyrood staff to convert Unit 3 in Synchronous Condenser Mode back to be a power generator was carried out during the week of January 07th to 10th 2020.

The findings indicated that the majority of time required to complete the task is due to the fact that at Holyrood the generator casing which is filled with hydrogen is being purged with Carbon Dioxide and then with air before the work permit is established which takes approximately two days. Maintenance staff then completes the re-coupling of the generator to the steam turbine in three 10-hour days. After the permit is surrendered the above procedure to establish a hydrogen environment in the generator casing is then carried out by reversing the above process which takes approximately another two days before the start-up commences.

Although a concern that safety was the reason for the degassing of the generator casing, the question was raised as to whether or not the generator purge was actually required. If the generator seal oil system is left in service with hydrogen in the casing and the use of sparkless tools were implemented during the uncoupling and recoupling process, the time needed to convert the unit in either direction would be reduced significantly. On checking with one other power producer who converted their generators routinely it was indicated they took three 10-hour days to do complete the task. This procedural change obviously is not an extensive research finding, however the staff at Holyrood might want to consider this as an option to improving the time.

A few options have been identified that could be considered to reduce changeover time:

- Eliminate the purging of hydrogen steps (as discussed above) – leave generator seal oil system in service with hydrogen in the casing and use sparkless tools during uncoupling and recoupling (i.e. appropriate tools and work methods) and gas monitoring – work protection code likely not an issue but HSE Committee and maintenance staff safety concerns would have to be addressed. Minimal costs. West coast utility had used approach before at their station before its end of steam date.
- Refitting the carbon dioxide and air filling and exhaust systems with larger pipes/capacity and adding carbon dioxide heaters to prevent freezing. Costs, moderate time saving impact.
- Leaving the CO2 in the generator and avoiding air fill step – costs, moderate time saving impact.
- Have conversion work done on 24 hours/day basis vs. current 10 hours /day mode (staff availability, overtime issues)
- Running one or more units (likely Unit 3 first) at very low minimum generation load (30 MW, after demonstration), but maximum MVAR output (100-130+ MVAR may be possible). Fuel cost; increased maintenance; Excitation system capability verification; spinning reserve capability; Auxiliary steam availability for oil heating and faster start of other units and building purposes.

19. Conclusions

The following major conclusions are based on the review of the issues and condition assessment documentation in this report. They are intended to highlight the key issues at a summary level.

19.1 Station and Units

1. Holyrood's overall condition is fair to good, good for its age. Units 1, 2, and 3 were installed in 1969, 1970 and 1979 respectively and are therefore approximately 50, 49, and 40 years of age respectively as of 2019. They will be 54, 53, and 44 years old as of 2023, and thus beyond the typical 40-year technical life of similar generation facilities (but less than 60 years that has been experienced in some cases).
2. Units have typically run seasonal base load between 50% and 100% MCR, not cycled, not two shifted, not overpressure. Given their historical seasonal base load and lightly loaded operating pattern, the condition of the units and the majority of major equipment/systems is more consistent with "operational ages" on the order of 30, 30, and 25 years, respectively.
3. The units are of a relatively modern cycle design, but with older parts and elements (i.e. manual valves).
4. The plant, with ongoing maintenance and inspection and focused capital investment, can reliably make the current March 2021 and an extended March 2023 end of generation date, and with Unit 3 generator refurbishments a 2043 Unit 3 synchronous condenser end date
5. Units 1, 2, and 3 have respectively operated about 200,000+ hrs, 200,000+ hrs, and 165,000 plus 55,000+ hrs synchronous condenser as of December 2019 (with very few starts/stops). 200,000 operating hours is typically when many older facilities require major refurbishment/rehab work or retirement
6. A great deal of refurbishment and replacement has occurred since 2010 (i.e. boiler surfaces, water supply, roads, air compressors, pumps, turbine overhauls, generator rewinds, exciter systems).
    a. Units 1, 2, 3 fuels up to 2007 and again in 2015 were poor quality that resulted in boiler reliability and life impacts and safety risks. Nevertheless, significant refurbishment and detailed inspection/repair work and cleaning have largely mitigated these.
7. Plant HR issues have been and continue to be an issue. Significant numbers of "Term staff" are employed and currently have letters recently to March 2022.
    a. Staff levels to the end of normal steam period should be continued at current levels. Numbers should be reduced to about 74 (including 12 diesel and gas turbine staff) for post March 2023 cold standby/emergency generation period
    b. Extensions of Term employee letters, preferably extensions to at least March 2023, are necessary to maintain suitable expertise and skillsets for safe operation.
    c. Start/stop exercising of equipment and employees is needed, particularly in post normal steam period.
    d. Operator skills, particularly in post normal steam period, would benefit significantly from use of a simulator, such as a nearly new unit available from OPG Thunder Bay station and fairly readily convertible to Holyrood.
    e. Operators, particularly in post normal steam period, should (with the co-operation of Hydro Unions) in extended non-operating periods be utilized in maintenance support.
8. Current Capital Plans (base and planned supplemental) represent a reasonable program to ensure safe and reliable generation operation to March 2023. Fine tuning and optimization on an annual basis based on condition assessment and PM's would be a reasonable expectation to minimize unnecessary investment while staying within acceptable risk tolerances

9. Units 1, 2, 3 can with the planned investments operate reliably and safely in generation mode to March 2023 generation end of life, and beyond in an emergency/standby mode to 2027+.
10. Unit 3 can with the planned investments operate reliably and safely in synchronous condensing mode up to a 2043 synchronous condensing end of life. This assumes that the Unit 3 generator will likely require a stator rewind at some point in the next 5 years and the pony motor/SSS clutch arrangement would be overhauled/modified probably within the next 5 years.
11. 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 the March 2023 end of Normal generation date, and identify issues for the post 2023 period. The identified priorities may be useful in better assessing future funding requirements. It is assumed that normal practices regarding inspections, maintenance, and PM work continues to end of normal generation life in March 2023, but inspection/overhaul interval times would be significantly increased in the post 2023 period.
12. The steam turbines are generally considered to be in good condition for an end of generation life of March 2023, although Unit 1 has vibration issues that require care and more time in start-up, with some specific issues identified in Chapters 8 to 10. Their condition supports the current 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. Post 2023, this inspection/overhaul period is expected to condition, and equivalent operating hours based (consider 30,000 equivalent hours, with maximum 12-15 years for the steam turbine and 12,000 equivalent hours, with maximum six to ten years for minor valve inspections).
13. The Units 1 and 2 generators are considered to be in fair to good condition, and able to meet the end of generation date of March 2023 without rewinds, assuming online monitoring and inspections are maintained. Inspections to at least summer 2021 should be maintained on current six-year cycle. The inspection/overhaul period is expected to be increased from current 6 years to a condition and equivalent operating hours basis post 2023 (consider 20,000 equivalent hours, to a maximum of 10 years).
14. The condition of Unit 3 generator, with stator rewinds in 2023-2025 and ongoing regular inspections and maintenance, is expected to be able to meet an end of synchronous generation life of 2043. A refurbishment of the SSS clutch is likely required sometime in the 2020 to 2025 timeframe. When decoupled from the turbine, Unit 3 generator uses a novel thrust bearing on a stub shaft insert section to address lateral movement during synchronous condensing operation to reduce long term vibration and damage. Either maintenance of the six-year inspection cycle or use of a condition and equivalent operating hours basis post 2023 (consider 20,000 equivalent hours, to a maximum of 10 years) should be acceptable for Unit 3 generator.
15. Holyrood's boilers are considered to have significant remaining life, beyond that required to meet a March 2023 end of generation, provided regular inspections and maintenance is maintained. Level 2 inspections and repair work since 2010/11 have addressed most of the high priority/high risk issues with the high pressure and temperature feedwater and steam lines, primarily main steam and hot reheat steam lines, especially on Units 1 and 2. Annual inspections and PM's, as well as Level 2 inspections identified for investigation in 2020 and 2021, should continue through generation end of life in March 2023 as very high priority safety and reliability due diligence task.
16. Holyrood's high-pressure feedwater heat exchangers have not been extensively tested, although they are checked and leak tested every year. They are considered capable to meet a 2023 end of generation service, with regular PM work.
17. Holyrood's deaerators are considered to have considerable remaining life, enough to meet a 2023 end of generation service. Inspections are done during the annual boiler inspection and maintenance work. Level 2

inspection of internals is recommended for 2021, if generation continues to March 2023 and standby/emergency beyond that.

18. Holyrood's low-pressure feedwater heat exchangers have not been tested beyond annual leak testing. They are considered capable to meet a 2023 end of generation service, with regular PM and repair work.
19. Holyrood's programs for major equipment, pumps, and motor inspection scheduling, and overall PM process has proven reasonable and effective. Inspection/overhaul timing should be re-evaluated for post steam period.
20. 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 might become an issue. Spares purchased since 2010/11 and ongoing maintenance has made it very likely that these will not impact reliable generation to the end of generation life in March 2023.
21. Much of the plant switchgear (Stage 1 and Stage 2), primarily many breakers, relays, and motor control centres, had reached a physical age where extensive replacements over the period 2014 to 2021 were considered important for plant reliability. The plant has instituted programs including spare parts and elements to enhance the reliability of these. Replacements required for Stage 2 (Unit 3 synchronous condensing) to 2043 should be examined and replacements implemented. The extent and implementation replacement/refurbishment of Stage 1 elements should be determined – needs for station service feeds and obsolescence issues for cold standby/emergency application.
22. Uncertainty over the plant future is impacting many decisions, such as:
    a. Fuel tank #'s, inspections, upgrades – regulatory decisions
    b. Investments and trials of "Faster Start", "Lower minimum load operation", and "Quicker Unit 3 conversion to/from synchronous condensing"
    c. Steam turbine valve and turbine overhauls; major equipment overhauls and replacements
    d. Scope of boiler overhauls
    e. Generator rewinds and overhauls
    f. Controls, Performance improvements

19.2 Site Conditions

1. The site is in generally in good condition.
2. Some underground sections of the site fire water system are in poor condition. Repairs are required in 2020 and 2021, and sections known to be in poor condition should be replaced in 2021 to 2024.
3. The plant access road is now in very good condition after repaving was done in 2017. On-site roads should have appropriate repairs/repaving.
4. The on-site landfill is nearing end of life and requires management as well as possible expansion or replacement.
5. Underground drainage facilities were upgraded in 2017 and should not require further work at present.

19.3 Common Facilities

1. The plant has implemented a number of measures to ensure sufficient oil delivery capability, while reducing costs (i.e. deferring major tank inspection expenses). Facilities are able to meet a 2021 end of generation service date, but will require more effort for March 2023 and beyond:
    a. Tank 1 inspection and life extension requires analysis and decisions on the costs of extensive repairs and the potential regulatory/fuel management impacts of having to continue operation to 2023 and beyond without it.
    b. Studies of Tank 2, 3, and 4 have shown that regulatory extensions for out of service inspections and refurbishments can be extended to 2027+. Requests have been submitted to Regulators, but no decisions identified. These need to be either granted or inspections/repairs made for both March 2023 and cold standby/emergency mode period.
    c. Retrofit of a Main Oil Tank recirculation system to at least one tank (or two) is highly desirable to promote mixing in the post 2023 period during long periods of storage.
    d. Retrofit of a Day Tank recirculation system (preferably from Unit 3) is needed to promote mixing in the post 2023 period during long periods of storage.
2. The main output 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. Main transformer on-line monitoring and testing has been implemented allowing better tracking of transformer conditions. Lesser transformers have had PCB replacements. All transformers are expected to meet the 2023 end of generation service life. Spares post March 2023 will provide additional capability for synchronous condensing operation reliability.
3. Circulating water intake and discharge structures and sumps and large concrete pipes from the pumphouses to the condensers and to the discharge siphon pits are able to meet the 2023 end of normal steam generation service life. Additional flexibility post 2023 for synchronous condensing operation exists. Post 2023 use is likely acceptable, subject to normal PM's and submersible camera inspections driven by condition.
4. A significant single contingency with the plant raw water supply has been addressed. The original line has had some refurbishment and the line has now been paralleled.
5. Some improvements have been made to the water treatment plant clarifier, sand filters, and clearwell. Regular PM's and any resulting work should mitigate unplanned (not necessarily long) shutdowns during the pre and post March 2023 periods. Some work on elements may be required (acid, caustic tanks) and should be assessed.
6. A new building heating system (auxiliary steam supply - from unit 3 or new system) needs to be operational before normal end of generation whether March 2021, 2022, or 2023. At present, no plan has been settled upon. Operation of Unit 3 boiler as a steam source for building heating, but also for cold standby/emergency readiness for quicker start-up including fuel preheating.
7. The waste water basin building remains in poor condition and access is restricted for human health reasons. A plan for its refurbishment is needed for both pre and post March 2023 periods.

19.4 Six 2 MW Black Start Diesel Generators, 120 MW Gas Turbine, and TS Switchyard Facilities

The six 2 MW Black Start Diesel Generators, 120 MW Gas Turbine, and TS Switchyard Facilities were not specifically addressed in this review, however a few comments are warranted.

1. The six 2 MW black start diesel units are relatively new and 2018 higher stacks have resolved issues with ground level emissions concentrations Switchyard Breakers and Disconnects.

2. The 120 MW gas turbine is relatively new and providing good service as a peaking unit. Provided regular maintenance and overhauls are maintained it should be in good condition for use through 2030 and beyond.
3. The switchyard and power transformers have had considerable updates undertaken since 2010/11 in terms of breaker replacements, power transformer assessments and continuous monitoring. Breaker replacements in the Holyrood TS in particular were accelerated after issues were identified with these during the 2014/15 system failures. These changes are planned to continue through 2020 and beyond, with the expectation that the TS will be in good condition to support the system, and the Holyrood facility as a generation site to March 2023 and beyond as required for synchronous condensing or generation.
4. Main power transformers may become an issue for life beyond March 2023, but continuous condition gas monitors should provide better indication of the timing. The spare power transformer provides some added security.
5. Where appropriate the facility's unit and station service and rectifying transformers have been/are being replaced as part of the overall PCB phase out program.

19.5 Holyrood TGS Facility Management

1. Overall Holyrood TGS facility management is excellent under the circumstances. There is a demonstrated practice of continuous improvement to the extent possible under difficult circumstances. 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. Holyrood TGS has experienced significant human resource challenges since it was announced that it would be substantially reduced in generation once Muskrat Falls came into service (Unit 3 is expected to remain as an operational Synchronous Condensing unit beyond 2023 to 2043).
    a. Several measures have been taken, working with the Union, to minimize or mitigate some of the impacts. There have been experienced "Term" staff retained through March 31, 2022 using premium rates.
    b. Several senior and intermediate people continue to migrate to other roles from Holyrood Operations: For example, eleven people moved in 2017, including a shift supervisor. Even with replacements getting on boarded typically with three months overlap, this has left the station with a significant portion of junior staff and/or others less experienced within the Holyrood station specifically. This has had the potential to impact both safety and reliability and is the focus of considerable effort.
    c. In general, plant management have done an excellent job in securing experienced staff. The challenge will however likely grow as 2023 approaches and as other parts of Nalcor are looking to secure experienced staff.

19.6 Environmental / Regulatory Assessment

1. The existing Certificate of Approval expires August 31, 2021. It covers among other things the Holyrood TGS, the Holyrood CT and the six diesel generators. A new Certificate of Approval and Operating licenses will be needed to extend operation for dates beyond March 31, 2021. A new application is to be submitted in writing by March 1, 2021. Even with a closure of Holyrood TGS in March 31, 2021, a new application for the diesels and CT would be required.

2. A new GHG plan will be needed for period beyond March 2021, and/or additional costs for GHG credits will have to be accounted for.

19.7 Quicker Start Assessment

1. Quicker starts on the order of 8 hours are possible from hot/warm status for the period up to March 2023. Pre-March 2023 criteria of 4 to 8 hours recall from hot standby can be achieved without major modifications to the plant equipment. Nevertheless, Wood considers that 2020 to 2021 is the time to engineer, test, and implement modifications for quicker start and lower loads for both the pre-March 2023 period, as well as for the cold standby/emergency mode period post March 2023
2. After extensive discussion with Operations and Maintenance Staff at Holyrood, Wood believes that all units at Holyrood can be started up much faster than historically typical for cold starts. Reaching the time criteria as laid out in the "2019 Holyrood Thermal Generating Station Condition Assessment & Life Extension Study" of 8-12 hours for one unit and up to 24 hours for the second unit is considered achievable with modest capital investment and operation changes. A number of changes need to be made in order for that to happen and are required during the time frame of 2020-2022 to demonstrate their viability and implement.
    a. First, there are changes required in mechanical design and installation (Chapter 16).
    b. Second, a mindset change within NLSO and Holyrood has to be established due to the new role in which Holyrood will be operated.
    c. Third, providing better training facilities to keep operating staff skill levels current including actual test starts in 2020 to provide confidence that these goals are achievable into the future.

19.8 Improving Unit 3 Changeover From/To Synchronous Condenser to a Power Generator

1. A significant reduction in the conversion time on Unit 3 from synchronous condenser to generator is possible. Options include:
    a. Leaving the hydrogen in the generator during conversion using appropriate work methods and tools, as has been done elsewhere in the past – this will require revised work practices and sparkless tools and monitoring. It will necessitate prior discussion re Work protection Code requirements and support from Holyrood HSE Committee and maintenance staff. Minimal costs. West coast utility had used approach before at their station before its end of steam date.
    b. Alternatively, improving the methods of purging the hydrogen from the generator casing: adding larger vents or increasing the carbon dioxide line sizing along with a carbon dioxide heater to prevent freeze ups of CO2 as it is being introduced. Costs, moderate time saving impact.
    c. Leaving the CO2 in the generator and avoiding air fill step – costs, moderate time saving impact.
    d. Have conversion work done on 24 hours/day basis vs. current 10 hours /day mode (staff availability, overtime issues)
    e. Running one or more units (likely Unit 3 first) at very low minimum generation load (30 MW, after demonstration), but maximum MVAR output (100-130+ MVAR may be possible). Fuel cost; increased maintenance; Excitation system capability verification; spinning reserve capability; Auxiliary steam availability for oil heating and faster start of other units and building purposes.

19.9 Holyrood Capital Plan Assessment

Capital Investments to 2019

Staff and management involved in capital improvements completed since 2010/11 and 2017 at Holyrood should be commended. All of the improvements have contributed to increase the reliability and overall life of the plant. A listing of significant capital improvements in the period 2015 to 2019 is presented in Chapter 5 (Table 5-1).

2019 Capital Plan Investments for March 2021 End of Steam Generation

Table 5-2 in Chapter 5 presents the 2019 capital plan which at the time assumed an end of steam date of March 31, 2021 (excluding subsequent supplemental projects to extend the normal operating mode period beyond March 31, 2021 to March 2023; or boiler overhauls, which are not capital). Most of these are for Stage 2/Unit 3 facilities or common facilities.

Wood concurs that they will be required for ongoing plant and Unit 3 synchronous condensing operation. They also believe that timely reviews annually of the list, prior to commitment are warranted depending on the status of system supply reliability at the time.

2019/2020 Capital Plan Supplemental Investments for March 2023 End of Normal Steam Generation

Holyrood will continue to need capital improvements, including some dedicated to the generation/steam side of the plant which for this study is March 2023. Some additional capital improvements that may be required are outside of the plant's jurisdiction such as the power transformers and switchyard equipment.

The HRD proposed supplemental projects (Chapter 13) to extend the normal operating mode from current March 31, 2021 to March 31, 2023 were developed in November 2019 (preliminary) and in March 2020 (final submitted) by Holyrood Assets. Wood in November 2019 provided a preliminary Letter of Support of the initial Hydro list and a final Letter of Support in March 2020 confirming its opinion that Hydro's capital lists were both necessary and reasonable to the continued safe and reliable operation of all three units as generating units at Holyrood in its current operating pattern to March 31, 2023.

2020/21/22 Capital for Faster Starts, Faster Unit 3 Conversion, and Lower Minimum Load

Wood believes that modest investments in studies, engineering, moderate facility additions, and testing to facilitate/establish the potential opportunities for lower minimum load and faster starts and quicker Unit 3 generator conversions are warranted in the 2020 to 2022 period. The costs for these are to be identified as part of an extension to this current study, planned for mid to late 2020.

These are expected to be able to provide some economic relief and system responsiveness in the 2020 to 2023 period, as well as facilitate any longer term cold standby/emergency operation if that were to prove desirable from a system flexibility and economic perspective (as was the case for the Ontario Power Generation Lennox Thermal Generating Station 4 x 500 MW heavy oil and natural gas steam plant).

20. Recommendations

20.1 Overall Station and Units

1. Maintain the ongoing inspection, testing, maintenance and PM activities through the end of steam normal operation mod period to March 31, 2023, adjusting to a condition/equivalent operating hours basis after March 2022. Address the specific actions identified in Chapters 8 to 10.
    - Retain 9-year major steam turbine inspection/overhaul interval until 2022; thereafter consider a 30,000 equivalent hours to maximum 12 years; subject to any unexpected changes in conditions found
    - Retain 3-year minor steam turbine valve inspection/overhaul interval until 2022; thereafter consider a 12,000 equivalent operating hours to maximum 8 years, subject to any unexpected changes in conditions found
    - Retain the 6-year generator inspection/overhaul interval until 2022; thereafter consider a 20,000 equivalent operating hours to maximum 10 years, subject to any unexpected changes in conditions found
    - Maintain existing programs for major equipment, pumps, and motor inspection scheduling and overall PM process, but adapting to condition and equivalent operating hour basis.
2. Assess and continue Level 2 condition assessment task inspections and testing identified in Chapters 8 to 11 (summarized in Chapter 12) through March 2022/23 generation end of life, particularly on boiler and high-pressure piping components.
3. Develop and implement an optimized plan for station switchgear (Stage 1, Stage 2) addressing a combination of spare components, replacement, and sparing to maintain Unit 3 synchronous condensing capability and station reliability without interrupting normal unit operation.
4. Undertake a Unit 3 generator stator rewind and generator/SSS clutch refurbishment in 2020/21 for post March 2021 synchronous condenser operation.

20.2 Common Facilities

1. Repair buried fire water system – immediate repairs and medium-term targeted replacements.
2. Continue transformer oil gas analyses (and analysis of on-line monitoring data) and transformer PM electrical testing as per regular inspection and maintenance plans.
3. Undertake ongoing integrity inspections of single contingency failure candidates including the dam at Quarry Brook, and the original water treatment plant clarifier, sand filters, and clearwell.
4. Implement a plan in 2020/21 for a new building heating system (auxiliary boiler/steam or electric) as needed for post steam period, whether March 2021, 2022, or 2023. It should consider the overall needs of pre and post steam periods, including the use of operation of Unit 3 boiler as a steam source for building heating, but also for cold standby/emergency readiness for quicker start-up including fuel preheating.
5. Assess the visibility of modifications to the oily water separator, and to the waste water basin building to address current corrosion, safe egress, and ventilation needs.

20.3 Six 2 MW Diesel Generators

1. Maintain maintenance and overhauls program.

20.4 Switchyard

1. Maintain maintenance and overhauls and replacement program, per TRO plans.

20.5 Environmental / Regulatory Assessment

1. Initiate process to submit in writing by March 1, 2021 an application for a revised Certificate of Approval for the Holyrood site facilities.

2. Develop a new GHG plan for period beyond March 2021, including any additional costs for GHG credits will have to be accounted for to address operations beyond March 31, 2021.

20.6 Quicker Start, Lower Minimum Load, Quicker Unit 3 Conversion Assessment

1. Develop in 2020 as part of an extension to this study a plan and test program to develop a quicker start program including costs (testing, capital and OMA), work process and settings changes, schedule, 2020/21 test program to determine the optimum path. Assess procurement of nearly new simulator from OPG Thunder Bay TGS for use in emergency/standby operating period.

20.7 Management

1. Continue to implement best practices, in a difficult environment.
2. Continue to monitor staff capabilities and find ways to augment staffing to optimize safety and reliable operation to end of generation life of March 2023, as well as for Unit 3 synchronous condensing to 2043.
3. Develop and maintain a succession planning process.
4. Develop and maintain a contingency plan for Unit 1 and 2 generation emergency operation to 2027+.

APPENDIX A
MARCH 25, 2020 Wood Letter of Support
Supplemental Capital Request by Newfoundland and Labrador Hydro

3 April 2020

205882-2.3.1

Mr. Jeff Vincent
Senior Manager, Thermal Generation
Holyrood TGS PO Box 12400
Hydro Place, 500 Columbus Drive
St. John's, NL
A1B 4K7

Dear Mr. Vincent:

Re: Holyrood Thermal Generating Station Supplemental Capital Projects

Wood is engaged by Newfoundland and Labrador Hydro (NLH) to provide technical consulting services for the Holyrood Thermal Generating Station (HRD). At the request of NLH, Wood provides the following opinion on four maintenance projects to be conducted in 2020.

1. **Unit 2 Generator Overhaul**
2. **Unit 2 Turbine Valve Overhaul**
3. **Boiler Condition Assessment and Miscellaneous Upgrades**
4. **Unit 3 Boiler Feed Pump West**

Overall, Wood believes that HRD is in fair to good condition and capable of reliable and safe operation to end of baseload production (year 2021, 2022, or 2023), and to operate in a cold standby mode beyond that. This capability depends on maintaining appropriate inspection, overhaul, maintenance, and capital investment activities.

Wood recommends that while the units at HRD are operating in a generating mode comparable to its historical manner, then the current inspection, overhaul and maintenance time-based cycles should be followed. When the units enter cold standby mode, those cycles should be adjusted to incorporate equivalent operating hours.

1. Unit 2 Generator Overhaul

The recommended inspection/overhaul cycle for generators was changed from nine years (typical of newer generators) to six years in 2012, based on the generator ages and on the condition assessments by GE and Wood generator experts in 2010/11. Unit 1 generator had inspections/overhauls in 2012 and then again in 2018. Unit 2's last inspection/overhaul was in 2014, so its normal six-year cycle would be 2020 as is proposed.

No generator rotor or stator rewinds have been done on Units 1 or 2 or are being proposed for Unit 2 in 2020. The scope of the Unit 2 work in 2020 has been identified as:

- Disassembly of generator end shields, hydrogen seals, hydrogen coolers, and bearings.
- Removal of the generator rotor from the stator.
- Cleaning of internal components.
- Detailed visual inspection and NDE of internal components including:
    - bearings.

PO Box 9600
133 Crosbie Road
St. John's, NL
A1A 3C1
Tel: (709)724-1900
Fax: (709)739-5458
woodplc.com

Wood Canada Limited

- oil deflectors.
- Replacement or refurbishment of components found to be damaged.

Based on review of the GE inspection reports since 2011, Wood recommends that the scope of proposed work is should be executed in 2020 to ensure continued reliable and safe operation until end of baseload production and afterwards, which may include operation as a synchronous condenser.

2. Unit 2 Turbine Valve Overhaul

The current inspection/overhaul cycle for steam turbine valves is three years and continuation of this cycle is critical to the safe and reliable operation of the steam turbines. The last Unit 2 turbine valve inspection / overhaul was in 2017, so completion of this work in 2020 is recommended.

The scope of work consists of a total disassembly, detailed internal inspection, and reassembly of all major steam valves. Valves will be refurbished through replacement of any damaged components identified in the inspections. Major steam turbine valves include:

- 6 x Control valves
- 1x Main stop valve
- 2x Reheat stop/intercept valves
- 1x Blowdown valve, and
- 7x Extraction steam check valves

3. Boiler Condition Assessment and Miscellaneous Upgrades

Wood, as part of the 2019 Condition Assessment and Life Extension study, reviewed the Electric Power Research Institute (EPRI) Level 2 condition assessments and B&W regulatory/annual inspection reports since 2011. NLH has done significant amounts of work in recent years that has improved both reliability and safety, particularly for Units 1 and 2 boilers.

Recent B&W work in 2018 and 2019 identified several boilers and auxiliaries' issues with Unit 3 boiler, as well as those remaining with Units 1 and 2. The proposed 2020 project (List of work scope in Attachment 1) is expected to address these.

Hydro has proposed for 2020 a Level 2 Condition Assessment on internal components of the main steam generators (boilers) to detail required refurbishment or replacement work. Additionally, Hydro would complete upgrades identified during the 2019 Condition Assessment and Miscellaneous Upgrades project. While Hydro, through the previous assessments, identified known equipment for immediate replacement, it is possible that additional components may require replacement as a result of the Condition Assessment work. The plant plans to follow the Inspection and Test Plan ("ITP") that was prepared for Holyrood TGS by Alstom (OEM for Unit 1 and Unit 2 boilers) and engineering consulting firm AMEC NSS. The ITP covers all boiler pressure parts and high energy piping. Inspection and test scope, assessment methods and intervals were developed using the OEM and consultant's knowledge and experience.

Wood fully supports and recommends that the work in Attachment 1 be undertaken in 2020, particularly in light of the uncertainty about the timing and future roles of the Units. If Holyrood

Description	Estimated Cost	Justification
Holyrood TGS Unit 1		
Internal boroscope inspection of Economizer Inlet Header including measurement of ligament cracks to track growth rate.	$37,500	Last inspected in 2017. B&W recommended re-inspection at three-year-intervals to monitor crack growth rate.
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Replacement of Sootblower 17R Aspirating Wallbox and Sleeve.	$22,000	Recommended based on condition assessed in 2019 when temporary repairs were performed to correct corrosion damage. Permanent repairs required to manage risk of sootblower impingement on wall tubes and jamming of moving parts on wall box if not replaced.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Replacement of the following three Down Comer Supports and leaking Header Expansion Joints: • 10th Floor - Cold Reheat Support, West Clamshell, "10B" • 10th Floor- Cold Reheat Support, East Clamshell, "10C" • 8th Floor- East MS, Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the following two observation ports: • 4th Floor - SW "A" Corner • 2nd Floor - SE "D" Corner	$96,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • Outlet Header • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Acceleratеed Corrosion of Economiser inlet piping bends on the 6th Floor.	$12,000	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections. Projected wear rates determined from measurements made in 2017 indicate that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.

Description	Estimated Cost	Justification
Holyrood TGS Unit 2		
Measurement of Ligament Crack Growth by internal boroscope inspection on Economiser Inlet Header.	$37,500	Recommended by B&W to prevent in-service failure based on wear rates determined through previous inspections indicating that wall thicknesses may fall below ASME minimum recommendations after the Winter 2019-2020 operating season.
Condition Assessment of the East and West Air Heater Hoppers and Drains. Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless Steel.	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Header Expansion Joints: • 10th Floor CRH Support West Clamshell "10B" • 8th Floor West Hot Reheat (HRH) Header Clamshell • 8th Floor East MS Header Clamshell • 8th Floor West MS Header Clamshell	$315,000	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Refurbishment of the 2nd Floor SW "A" Corner Observation Ports.	$82,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Condition Assessment of Forced Draft Fans.	$45,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$142,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Replacement of expansion joints at the following two locations on Superheater 1: • SH-1 Outlet Header 6th Floor West • Spacer Tube Antler	$30,500	Recommended by B&W based on assesed condition at 2019 inspection to minimise risk of leakage of toxic flue gas into the powerhouse along with resultant safety risk and PPE requirements Annual inspections are performed to identify leaks which occur frequently on these high-fatigue components. Previous similar upgrades have provided significant reduction in the amount of toxic gas released into the powerhouse.
Inspection for Flow Acceleratеed Corrosion of Economiser inlet piping bends on the 6th Floor at the North Side of the Boiler.	$12,000	Recommended by B&W at maximum 3.5 year intervals to minimise based on historic wear rates. Components were replaced in 2017 due to Flow Accelerated Corrosion.

Description	Estimated Cost	Justification
Holyrood TGS Unit 3		
Inspection of Boiler Feed Pump Piping Discharge Eccentric Reducer and "Y" for Flow Accelerated Corrosion.	$26,000	Recommended by B&W to prevent in-service failure based on maintenance experience at HTGS . The "Y" Was replaced in 2016 due to advanced Flow Accelerated Corrosion.
Inspection of Main Steam Turbine Terminal to monitor Creep & Thinning.	$32,500	Recommended by B&W at 3-year intervals based on findings of inspections completed in 2017 in which minor degredation and thinning were found.
Condition Assessment of the East and West Air Heater Hoppers and Drains and Replacement of: corroded piping sections, bottom of hoppers and spool between hoppers and valves. Ferrous pipe and fitting materials will be upgraded to Stainless	$30,000	Required to ensure reliability. Corrosion in this area is problematic. In 2019 many leaks were noted between the bottom of hoppers and the drain valves during water washes and chemical cleanings . Prevous partial Stainless-Steel upgrades since 2016 have been successful in preventing corrosion with no significant corrosion observed on replaced components to date.
Refurbishment of the 3rd Floor Southwest corner observation ports.	$82,500	Recommendated by B&W based on assessed-condition at 2019 inspection in order to: • Prevent leakage of toxic gas into occupiable space. • Maintain availability of sight lines into furnace.
Investion of Windbox Corner Attachment failures including design and install of improved attachment method.	$45,000	Required to improve reliability of Windbox corner attachments which are prone to failure most recently causing a forced outage in 2018
Full interior and exterior inspection of Deaerator Heater and Storage Tank.	$62,000	B&W recommend full inspection of similar B&W units at 5 year interval in order to evaluate FAC (Flow Accelerated Corrosion) or other corrosion damage that could impact the integrity of the pressure boundary. Previous inspection was more than eight years ago.
Detailed Condition Assessment of Air Heater including OEM technical assistance, inspection and service guidance.	$47,500	Recommended by B&W engineering to support extension of life.
Condition Assessment of Forced Draft Fans.	$45,500	Recommended by B&W engineering to support extension of life.
Replacement of all Air Heater Stationary Circumferential Sealing Angles on the East and West Air Heaters at both the hot & cold ends.	$146,000	Recommended by B&W based on assesed condition at 2019 inspection to prevent forced outages caused by jamming seals. Degraded Sealing Angles allow leakage past circumferential seals, reducing efficiency and accelerating degradation of the seals. Required to prevent forced outages caused by jamming seals.
Sampling and Analysis of Waterwall tubes including mechanical properties testing, deposition rate measurement and deposit chemical analysis.	$31,500	Recommended at three-year intervals by B&W to monitor deposit weight density and mechanical condition which will be used to inform chemical cleaning requirments.

STUDY INFORMATION SOURCES

The following information sources were among those used, through access provided by Newfoundland & Labrador related to various Holyrood TGS Condition Assessment Folders and files.

1. Hatch Report, Final Report for Holyrood 2017 Condition Assessment Report. H3544367-240-066-0001, Rev 2. June 19, 2018.
2. Stantec Report, Report on Concrete Coring and Testing, Pumphouse No. 1, Holyrood Generating Stations, Holyrood NL. Nov 2, 2017. File 12621472
3. Report, Tank 1 API 653 In-service Inspection Report – Nalcor Tank #1 Holyrood Generating Station, July 2016
4. Report, Tank 2 API 653 Out-of-service Inspection Report – Nalcor Tank #2 Holyrood Generating Station, Dec 2008
5. Report, Tank 3 API 653 Out-of-service Inspection Report, November 2003
6. Report, Tank 3 API 653 Inspection Report, June 2013
7. Hatch HTGS Unit 2 Stack Assessment, Hatch Nov 26, 2018
8. Babcock Newfoundland Hydro #1, #2, #3 Stacks. Rep Q 07.04.16
9. Babcock Newfoundland Hydro #3 Stack Rep Q 18.12.15
10. Babcock Newfoundland Hydro #3 Stack. Lo Rez Oct 22, 2015
11. Holyrood Site Stack #1 Report
12. Holyrood Site Stack #2 Report
13. HTGS 2017 Unit # 2 DA Heater Examination Reports. 2017 Sep 15
14. Babcock Report. 238-10-6011-164 RH-2 mark up Unit 1 2019 Repair
15. Unit #1 Economizer Inlet Header Borescope Report. Vis-tech Report#: HR1-01-17B. 2017 sep8-10
16. Team Industrial Auxiliary Steam Piping to Tank Farm LRUT Report. October 2017
17. Wayland Engineering Ltd, Metallurgical Assessment of WaterWall Tube, Holyrood GS Unit #3 for Babcock & Wilcox PPG. Report 1924A. July 15, 2019
18. Holyrood 1 and 2 Tube Analyses' Results. Lignley S.C. to J. Curtis Email. 11/05/2017 11:37 PM
19. HTGS 2017 Unit # 1 FD Fan NDE Reports. Aug 24, 2017
20. HTGS 2017 Unit # 2 FD Fan NDE Reports. Sep 8, 2017
21. HTGS 2017 Unit # 3 FD Fan NDE Reports. June 14, 2017
22. Babcock Wilcox JL Hydro Holy Rood Station. A022384 Field Service Report, J. Richmond Jul 7, 2015 Unit 2 Inspection
23. Babcock Wilcox JL Hydro Holyrood Station A028042 Field Service Report, C. Irving 8-12-16 Unit 2 Repairs
24. Babcock Wilcox JL Hydro Holyrood Station A028042-01 Field Service Report. A. Cross Unit 1 Sep 2016
25. Babcock Wilcox JL Hydro Holyrood Station A031090 Field Service Report J. Krizon 6-5-17 Unit 3 APH
26. Babcock Wilcox JL Hydro Holyrood Station A031090-01 Field Service Report. A. Cross 8-17-17 Unit 1 APH
27. Babcock Wilcox JL Hydro Holyrood Station A031090-02 Field Service Report. R. Parsley 9-2017 Unit 2 APH
28. Babcock Wilcox JL Hydro Holy Rood Station A031090-03 - Field Service advisory - BW - NL Hydro Holyrood Station - GGoetschius - 12-2-17 Unit 1 High Press Drop
29. Holyrood Station HOW 0828 (6-28-14) June 28, 2014 Unit 1
30. 2415-18 Report Stack #1 (Low Res) Dec 19, 2018
31. 2415-18 Report Stack #2 (Low Res) Nov 28, 2018
32. 2415-18 Report Stack #3 (Low Res) Dec 21, 2018

33. Team Industrial Letter - Tank 1 Oct 4, 2018
34. Team Industrial Tank 1 - Inspection Interval Extension Report – October 2018
35. Tank In-Service Inspection Report Nalcor Tank #1 Holyrood Gen Stn R1
36. Team Industrial Letter - Tank 2 2019 Oct.29
37. Team Industrial Tank 2 - Inspection Interval Extension Report Oct 29, 2019
38. Team Industrial Tank 2 API Inspection Report 2008
39. Team Industrial 092019 Tank 3 Letter Aug 29, 2019
40. Team Industrial NL Hydro Tank 3 API 653 In-Service Inspection Report June 2018
41. Tank 3 API 653 Out of Service Inspection 2013
42. Team Industrial 092019 Tank 4 Letter Aug 29, 2019
43. Team Industrial NL Hydro Tank 4 API 653 In-Service Inspection Report June 2018
44. Team Industrial Tank No 4 API out of Service Inspection Report 2010
45. Hatch Jetty Fenders - H361253-00000-240-024-0001pdf_0_V3-FINAL
46. Hatch Holyrood Marine Terminal 10 Year Life Extension - H353306-00000-240-230-0001pdf_0_V2 Mar 21, 2018
47. Hatch - H355807-B-E-0006
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49. General Electric U1 Turbine Valve Outage Report Jul-Oct 2018
50. General Electric Steam Turbine and Generator Inspection Report. Valve and Generator Outage 2019. Holyrood. Equipment serial # HTS0004 06/19/2019
51. FSR 065910 Generator Ken Roberts 2016 Unit 3 Gen Overhaul
52. FSR_065909_Valve_Ken Roberts 2016 Unit 3 Valve Overhaul
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54. General Electric 2016 GE Turbine Valve Major Unit 3
55. General Electric U1 Generator Outage Report Nov 2018
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57. NALCOR Holyrood Unit #2 Minor Valve Inspection 2017
58. Holyrood Rotor RSO Field Service Report CFSR28102017
59. Unit #2 - PSH Tube Failure Summary 2016
60. Unit #2 - PSH Tube Failure Summary 2014
61. Unit #1 & #2 Summary of RH Repairs 2016
62. U2 Lower RH Replacement Summary 2016
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64. June 2017 Holyrood Derate Investigation Summary Presentation DR
65. JM Final Report 20180613
66. Howden Recommendations – pressure drop 2017/18
67. Alstom ESO-003817 2014 PSH Tube Failure Analysis
68. Dan Regan Site visit report Load Limit Operations Review NLH October 2016
69. Babcock & Wilcox – B &W Eng Recommendation Unit #2 RH 2012
70. HTGS Out Buildings Fire Detection - Project Binder 2019
71. Annual Inspection Report - Atlantic Crane 2018 Powerhouse Cranes
72. Hatch H355807-00000-240-030-0002 Marine Terminal Line Modification Feb 2018
73. Vacuum Pump DCI Report 2018
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75. U2 West BF Pump - Service Report May 26, 2017
76. Babcock & Wilcox – B&W Boiler 2018 Condition Assessment Report
77. AMEC 2017 Condition Assessment Level 2 Report
78. AMEC 2015-2016 Condition Assessment Level 2 Report

79. WOOD 2017 Condition Assessment Report Level 1 Refresh
80. Babcock & Wilcox – B&W Boiler 2019 Condition Assessment Report
81. Government of Newfoundland and Labrador Certificate of Approval Oct 31, 2016. Amendment: April 2, 2018 Approval No. AA16-105640A. File No. 716.008, 716.050.1
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83. AMEC 2012-13 Condition Assessment Report. Holyrood Thermal Generating Station Condition Assessment and Life Extension Study – Phase 2 2012/13 Level II Condition Assessment Boiler and High-Energy Piping. AM132/RP/005 R03 Nov 13, 2013
84. NLH-Liberty Recommendations - Hydro's Response to Boards Letter dated October 22, 2019 - 2019-10-31
    a. PUB-NLH-005
    b. PUB-NLH-048
    c. PUB-NLH-049
    d. PUB-NLH-050
    e. PUB-NLH-051
    f. PUB-NLH-069
85. NLH - Liberty Recommendations - Further Information - 2019-10-22
86. NLH - Liberty Recommendations - Request for Comments - 2019-09-12
87. NLH - RFIs - PUB-NLH-001 to PUB-NLH-057 - 2019-04-29
88. NLH - RFIs - PUB-NLH-058 to PUB-NLH-079 - 2019-06-04
89. Boland Marine, Marine Terminal Inspection
90. Hatch Nov 15, 2013 Day Tank API 653 Inspection
91. Holyrood Insurance Information for Darren Marsh 2019 Questions 2 to 25
92. Hatch Report H355506-00000-240-230-0001, Holyrood Marine Terminal 10-Year Life Extension Study, March 21, 2018
93. Letter. Newfoundland and Labrador Government to Newfoundland and Labrador Hydro/Terry Smith, Manager Safety, Health and Environment Jan 29, 2019. Re: API-653 Out-of-Service Internal Inspection Tank 1 & 2 Deferral

APPENDIX B
Holyrood Certificate of Approval

Newfoundland Labrador

GOVERNMENT OF
NEWFOUNDLAND AND LABRADOR
Department of Municipal Affairs and Environment

CERTIFICATE OF APPROVAL

Pursuant to the Environmental Protection Act, SNL 2002 c E-14.2 Section 83

Issue Date: ***October 31, 2016*** Approval No. AA16-105640A

Amendment: ***April 2, 2018***

Expiration: ***August 31, 2021*** File No. 716.008, 716.050.1

Proponent: **Newfoundland and Labrador Hydro**
P.O. Box 29
Holyrood, NL
A0A 2R0

Attention: Rod Healey, Environment Department Manager

Re: **Holyrood Thermal Generating Station, 123 MW Combustion Turbine and Six (6) Diesel Generating Units**

Approval is hereby given for the operation of a 123 MW Combustion Turbine, Six (6) Diesel Generating Units and a Thermal Generating Station, including power house, wastewater treatment plant, hazardous waste landfill and associated works located at Holyrood, NL.

This Certificate of Approval does not release the proponent from the obligation to obtain appropriate approvals from other concerned provincial, federal and municipal agencies. Nothing in this Certificate of Approval negates any regulatory requirement placed on the proponent. Where there is a conflict between conditions in this Certificate of Approval and a regulation, the requirements in the regulation shall take precedence. Approval from the Department of Environment and Climate Change shall be obtained prior to any significant change in the design, construction, installation, or operation of the facility, including any future expansion of the works. This Certificate of Approval shall not be sold, assigned, transferred, leased, mortgaged, sublet or otherwise alienated by the proponent without obtaining prior approval from the Minister.

This Certificate of Approval is subject to the terms and conditions as contained therein, as may be revised from time to time by the Department. Failure to comply with any of the terms and conditions may render this Certificate of Approval null and void, may require the proponent to cease all activities associated with this Certificate of Approval, may place the proponent and its agent(s) in violation of the *Environmental Protection Act*, and will make the proponent responsible for taking such remedial measures as may be prescribed by the Department. The Department reserves the right to add, delete or modify conditions to correct errors in the Certificate of Approval or to address significant environmental or health concerns.

For **MINISTER**

TERMS AND CONDITIONS FOR APPROVAL No. AA16-105640A
April 2, 2018

General

1. This Certificate of Approval is for the operation of a 123 MW Combustion Turbine, Six (6) Diesel Generating Units and a Thermal Generating Station, including power house, wastewater treatment plant, hazardous waste landfill and associated works located at Holyrood, Newfoundland. Extensive future expansion or change of activities will require a separate Certificate of Approval.

2. Certificate of Approval AA16-105640 is revoked and replaced by this Certificate of Approval.

3. Any inquiries concerning this Approval shall be directed to the St. John's office of the Pollution Prevention Division (telephone: (709) 729-2556; or facsimile: (709) 729-6969).

4. In this Certificate of Approval:

   - **accredited** means the formal recognition of the competence of a laboratory to carry out specific functions;
   - **acutely lethal** means that the effluent at 100% concentration kills more than 50% of the rainbow trout subjected to it during a 96-hour period, when tested in accordance with the ALT;
   - **administrative boundary** means the boundary surrounding the Thermal Generating Station outside of which the ambient air quality standards, outlined in Schedule A of the ***Air Pollution Control Regulations, 2004***, apply;
   - **air contaminant** means any discharge, release, or other propagation into the air and includes, but is not limited to, dust, fumes, mist, smoke, particulate matter, vapours, gases, odours, odorous substances, acids, soot, grime or any combination of them;
   - **ALT (acute lethality test)** means a test conducted as per Environment and Climate Change Canada's Environmental Protection Service reference method EPS/1/RM-13 Section 5 or 6;
   - **BOD_5** means biochemical oxygen demand (5 day test);
   - **CEMS** means the continuous emissions monitoring system used to measure gaseous releases of SO_2, NO_x, CO_2, CO and O_2 from each boiler;
   - **CO** means carbon monoxide;
   - **CO_2** means carbon dioxide;
   - **Combustion Turbine (CT)** means the 123 MW combustion turbine;

- **Department** means the Department of Municipal Affairs and Environment and its successors;
- **Director** means the Director of the Pollution Prevention Division of the Department;
- **discharge criteria** means the maximum allowable levels for the parameters listed in Table 3;
- **EDMS** means Environmental Data Management System;
- **GAP** means *Storage and Handling of Gasoline and Associated Products Regulations, 2003;*
- **grab sample** means a quantity of undiluted sample collected at any given time;
- **hazardous waste** means a product, substance or organism that is intended for disposal or recycling, including storage prior to disposal or recycling, and that:
  (a) is listed in Schedule III of the *Export and Import of Hazardous Waste Regulations under the Canadian Environmental Protection Act, 1999*;
  (b) is included in any of Classes 2 to 6, and 8 and 9 of the *Transportation of Dangerous Goods Regulations* under the *Transportation of Dangerous Goods Act, 1992*; or
  (c) exhibits a hazard classification of a gas, a flammable liquid, an oxidizer, or a substance that is dangerously reactive, toxic, infectious, corrosive or environmentally hazardous;
- **HYDRO** means Newfoundland and Labrador Hydro;
- **Landfill Operations Manual** means the Hydro Procedure Manual for the Controlled Waste Landfill (most recent version);
- **licensed** means has a Certificate of Approval issued by the Minister to conduct an activity;
- **liquid waste** is defined by the *Slump Test* (Canadian Standards Association test method A23.2-5C for determining the slump of concrete). The liquid waste slump test involves placing the waste in a 30 cm open inverted cone. The cone is removed and the immediate decrease (slump) in height of the waste material is measured. If the material slumps such that the original height is reduced by 15 cm or more, the waste is considered liquid;
- **leachate holding pond** means the detention pond for leachate control prior to transfer to the on-site wastewater treatment plant;
- **malfunction** means any sudden, infrequent and not reasonably preventable failure of air pollution control equipment, wastewater treatment equipment, process equipment, or a process to operate in a normal or usual manner. Failures, caused in part by poor maintenance or careless operation, are not malfunctions;

- **Minister** means the Minister of the Department;
- **MW** means megawatt;
- **NO_x** means oxides of nitrogen;
- **NO_2** means nitrogen dioxide;
- **O_2** means oxygen;
- **PCBs** means polychlorinated biphenyls;
- **Plan** means the specific plan as identified in the section of this Approval within which it is used. For example, in the *Waste Management Plan* section it refers to the Waste Management Plan;
- **$PM_{2.5}$** means particulate matter with a diameter of 2.5μm or less;
- **PPMV** means parts per million by volume;
- **proficiency testing** means the use of inter-laboratory comparisons to determine the performance of individual laboratories for specific tests or measurements;
- **QA/QC** means Quality Assurance/Quality Control;
- **register(ed)**, in the context of storage tanks, means that information regarding the storage tank system has been submitted to a Service NL office and a registration number has been assigned to the storage tank system. In the context of dispersion modelling, registered means submitted to and approved by the Department in accordance with departmental policy and guidelines;
- **regulated substance** means a substance subject to discharge limit(s) under the *Environmental Control Water and Sewage Regulations, 2003*;
- **SO_2** means sulfur dioxide;
- **SOP** means Standard Operating Procedure;
- **spill or spillage** means a loss of gasoline or associated product in excess of 70 litres from a storage tank system, pipeline, tank vessel or vehicle, or an uncontrolled release of any volume of a regulated substance onto or into soil or a body of water;
- **stack** means a chimney, flue, conduit or duct arranged to conduct an air contaminant into the environment;
- **storage tank system** means a tank and all vent, fill and withdrawal piping associated with it installed in a fixed location and includes a temporary arrangement;
- **TDS** means total dissolved solids;
- **TPH** means total petroleum hydrocarbons, as measured by the Atlantic PIRI

method;

- **TSP** means total suspended particulate with diameter less than100µm. For the purpose of this Approval, TSP shall be measured using a high volume TSP sampler;

- **TSS** means total suspended solids;

- **used lubricating oil** means lubricating oil that as a result of its use, storage or handling, is altered so that it is no longer suitable for its intended purpose but is suitable for refining or other permitted uses;

- **used oil** means a used lubricating oil or waste oil;

- **waste oil** means an oil that as a result of contamination by any means or by its use, is altered so that it is no longer suitable for its intended purpose; and

- **wastewater treatment plant (WWTP)** means HYDRO's treatment plant for wastewater streams resulting from periodic cleaning of boiler fireside equipment, and includes the periodic basin, the batch reactor, filter press and all associated works.

5. All necessary measures shall be taken to ensure compliance with all applicable acts, regulations, policies and guidelines, including the following, or their successors:

- *Environmental Protection Act*;
- *Water Resources Act*;
- *Air Pollution Control Regulations, 2004;*
- *Environmental Control Water and Sewage Regulations, 2003;*
- *Halocarbon Regulations;*
- *Storage and Handling of Gasoline and Associated Products Regulations, 2003;*
- *Used Oil Control Regulations;*
- *Storage of PCB Waste Regulations, 2003;*
- *Ambient Air Monitoring Guidance Document;*
- *Sampling of Water and Wastewater - Industrial Effluent Applications Guidance Document;*
- *Accredited Laboratory Policy;*
- *Compliance Determination Guidance Document;*
- *Stack Emission Testing Guidance Document;*
- *Plume Dispersion Modelling Guidance Document;*
- *Guidance Document for the Management of Impacted Sites.*

This Approval provides terms and conditions to satisfy various requirements of the above listed acts, regulations, policies and guidelines. If it appears that any of the pertinent requirements of these acts, regulations, policies and guidelines are not being met, then a further review of the works shall be conducted, and suitable pollution control measures may be required by the Minister.

6. All reasonable efforts shall be taken to minimize the impact of the operation on the environment. Such efforts include:

- minimizing the area disturbed by the operation,
- minimizing air or water pollution,

- finding alternative uses, acceptable to the Director, for waste or rejected materials,
- removing equipment or structures when they no longer have further use, and
- considering the requirement for the eventual rehabilitation of disturbed areas when planning the development of any area on the facility property.

7. HYDRO shall provide to the Department, within a reasonable time, any information, records, reports or access to data requested or specified by the Department.

8. HYDRO shall keep all records or other documents required by this Approval at the Thermal Generating Facility location for a period of not less than three (3) years, beginning the day they were made. These records shall be made available for review by officials of the Department or Service NL when requested.

9. Should HYDRO wish to deviate in any way from the terms and conditions of this Certificate of Approval, a written request detailing the proposed deviation shall be made to the Minister. HYDRO shall comply with the most current terms and conditions until the Minister has authorized otherwise. In the case of meeting a deadline requirement, the request shall be made at least 60 days ahead of the applicable date as specified in this Approval or elsewhere by the Department.

Waste Management

10. All waste generated at the facility is subject to compliance with the ***Environmental Protection Act***. All non-industrial waste shall be stored in a manner acceptable to the Department and, on at least a weekly basis, be disposed of:

- at an authorized waste disposal site, with the permission of the owner/operator of the site; or
- by some other means acceptable to the Department.

If required, industrial waste shall be disposed of by a licensed operator.

11. HYDRO shall ensure that all volatile chemical and solvent wastes, if they cannot be reused, are placed in suitable covered containers for disposal in a manner acceptable to the Department. Disposal of liquid wastes at waste disposal sites in the province is not permitted.

12. Disposal of hazardous waste in a municipal or regional waste disposal site in this Province is prohibited. Transporters of hazardous waste shall have an approval issued by the Minister. Those generating hazardous waste shall have a waste generator's number issued by the Director and shall also complete the required information outlined in the Waste Manifest Form.

Waste Management Plan

13. HYDRO shall revise and submit the Waste Management Plan for their Combustion Turbine and Thermal Generating Station including the six (6) Diesel Generators by ***October 31, 2018***. Every year the Plan shall be reviewed and revised as necessary, accounting for expanding or alteration of activities. All proposed revisions shall be submitted to the Director for review. The Department will acknowledge receipt of the Plan and/or revisions, and shall provide any review comments within a

reasonable time frame.

Noise

14. HYDRO shall revise and submit the Noise Management Plan for their Combustion Turbine and Thermal Generating Station including the six (6) Diesel Generators by ***October 31, 2018***. Every year the Plan shall be reviewed and revised as necessary. All proposed revisions shall be submitted to the Director for review. The Department will acknowledge receipt of the Plan and/or revisions, and shall provide any review comments within a reasonable time frame.

Chemical Operations

15. All chemical loading and blending shall be performed in a controlled environment with an effort to minimise or eliminate the release of any fugitive emissions or odours.

Spill Prevention and Containment

16. Areas in which chemicals are used or stored shall have spill containment systems constructed with impermeable floors, walls, dykes or curbs as applicable and be configured, maintained, inspected and repaired as follows:

- they shall not discharge to the environment;
- they shall have an effective secondary containment capacity of at least 110% of the chemical storage tank capacity, in the case of a single storage container;
- if there is more than one storage container, the spill containment system shall be able to retain no less than 110% of the capacity of the largest container or 100 % of the capacity of the largest container plus 10% of the aggregate capacity of all additional containers, whichever is greater;
- they shall be kept clear of material that may compromise the containment capacity;
- they may include a floor drain system provided that the floor drains, and the place or device to which they drain, are configured in such a manner that the required effective secondary containment capacity is maintained;
- every year they shall be visually inspected for their liquid containing integrity, and repairs shall be made when required; and
- once every ten years, spill containment systems shall be inspected, by a means other than visual inspection, for their liquid containing integrity, and repairs shall be made when required.

Contingency Plan

17. HYDRO shall revise and submit the Contingency Plan for their Combustion Turbine and Thermal Generating Station including the six (6) Diesel Generators at Holyrood by ***October 31, 2018***. This Plan describes the actions to be taken in the event of a spill of a toxic or hazardous material. Copies of the Plan shall be placed in convenient areas throughout the facility so that employees can easily refer to it when needed. HYDRO shall ensure that all employees are aware of the Plan and understand the procedures and the reporting protocol to be followed in the event of

an emergency. An annual response exercise is recommended for response personnel. Every year, as a minimum, the Plan shall be reviewed and revised as necessary. Any proposed significant revisions shall be submitted to the Director for review. Changes which are not considered significant include minor variations in equipment or personnel characteristics which do not affect implementation of the Plan.

18. Every time HYDRO implements the Contingency Plan, information shall be recorded for future reference. This will assist in reviewing and updating the Plan. The record is to consist of all incidents with environmental implications, and include such details as:

- date;
- time of day;
- type of incident (i.e. liquid spill, gas leak, granular chemical spill, equipment malfunction, etc.);
- actions taken;
- problems encountered; and
- other relevant information that would aid in later review of the Plan performance.

Each incident report shall be submitted to the Department as per the ***Reporting*** section.

Site Decommissioning and Restoration

19. A preliminary Decommissioning Plan, entitled "*Decommissioning and Demolition of the Holyrood Thermal Generating Station, dated July 29, 2016*" has been submitted to the Department on February 23, 2018.

20. A detailed Decommissioning Plan that includes measures to restore areas disturbed by the operation shall be submitted to the Director for review at least six (6) months prior to the cessation of operations at the Thermal Generating Station's power house. For guidance on the preparation of the Decommissioning Plans, refer to Appendix A.

21. As part of the site decommissioning and restoration process, HYDRO shall employ a registered Site Professional to complete a site-wide environmental site assessment, as defined in the ***Guidance Document for the Management of Impacted Sites***. Should impacts be identified, HYDRO shall proceed through the process outlined in the ***Guidance Document for the Management of Impacted Sites*** to achieve regulatory site closure.

Fuel Usage, Fuel Storage & Offloading

22. HYDRO is permitted to accept and combust in its Combustion Turbine ultra-low sulfur diesel oil.

23. HYDRO shall not combust Heavy Fuel Oil with sulfur content greater than **0.7%** by weight in the Thermal Generating Station.

24. HYDRO is permitted to accept and burn alternative fuel only with the written approval of the Department.

25. The diesel fuel offloading, storage and handling area for the new CT shall have an impermeable surface with an oil containment or collection system routed towards an oil/water-separator. Care shall be taken to prevent spillage on the ground and to the surrounding environment, particularly streams and other water bodies.

26. HYDRO shall maintain, and submit to the Director on a monthly basis as per the ***Reporting*** section, the following information:

- Name of Supplier, date and volume of each shipment of ultra-low sulfur diesel oil received; and
- Hourly diesel oil usage of new CT in litres per hour.

27. HYDRO shall analyze each delivery of Heavy Fuel Oil for the parameters listed in Table 1. Analysis shall be on a representative sample of the Heavy Fuel Oil received.

Table 1 – Heavy Fuel Oil Analysis Program			
Parameters			**Frequency**
A.P.I Gravity @60 ºF Pour Point Sulfur% by Weight Sediment % by Weight Aluminum Sodium	Density (kg/m^3 @ 15 ºC) Viscosity cSt @ 50 ºC BTU's per US Gallon Water % by Volume Nickel Vanadium	Flash Point Ash % by Weight Asphaltenes % by Weight Silicon	**Every Batch Delivered**

28. HYDRO shall maintain, and submit to the Director as per ***Reporting*** section, a record of all Heavy Fuel Oil received. The record shall include:

- name of the supplier;
- date and volume of the Heavy Fuel Oil offloaded;
- the certificate of analysis for each batch of Heavy Fuel Oil delivery received; and
- the name of the laboratory where analysis was performed.

Combustion Turbine Operations

29. HYDRO shall maintain, and submit to the Director on a monthly basis as per the ***Reporting*** section, the following information:

- date and hours of operation of the Combustion Turbine;
- date and time of start-up and shutdown of the Combustion Turbine;
- specification of all maintenance performed on the Combustion Turbine and/or associated water injection system, including the date and time the work commenced and completed; and
- total litres of water flow per hour for each hour of the day when the Combustion Turbine is in operation.

30. The Combustion Turbine facility shall have an impermeable surface with an oil containment or collection system routed to an oil/water separator.

31. All floor drains from the main building of the Combustion Turbine shall be directed to the oil/water separator prior to release into the Indian Pond.

32. HYDRO shall operate the Combustion Turbine water treatment plant as per manufacturer standards.

Diesel Generators

33. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **87% load** from **6:00 AM** to **10:00 AM** and from **4:00 PM** to **8:00 PM** to generate up to **8 MW** of power from ***November 1*** to ***April 30*** for peaking purposes.

34. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **67% load**, 24 hours a day, 365 days a year to generate up to **6 MW** of power for emergency purposes.

35. HYDRO shall complete the required stack modifications on all six diesel generators [as described in their revised (February 28, 2018) project schedule-70154TB, dated September 27, 2017] by ***June 30, 2018***.

Storage Tanks

36. All on site storage of petroleum shall comply with the ***Storage and Handling of Gasoline and Associated Products Regulations, 2003***, or its successor. Storage tank systems shall be registered with Service NL. All aboveground storage tanks shall be clearly and visibly labelled with their GAP registration numbers.

37. HYDRO shall implement the API-653, "*Tank Inspection, Repair, Alteration and Reconstruction*" in accordance with common industry practice.

38. An inventory of all petroleum storage tanks shall be submitted to the Director for review by ***June 30, 2018***. This inventory shall include the following:

- site plan showing tank location,
- registration number (where applicable),
- identification number,
- material stored,
- capacity,
- annual throughput,
- tank material,
- tank type,
- tank diameter,
- tank height,
- tank colour,
- roof type,
- year of manufacture,
- date of installation,
- date of last inspection,

- failure history,
- maintenance history,
- secondary containment capacity, and
- date of next planned inspection.

Every two (2) years, an update of any changes to the inventory shall be submitted to the Director.

Used Oil

39. Used oil shall be retained in an approved tank or closed container, and disposed of by a company licensed for handling and disposal of used oil products.

40. HYDRO shall submit a revised SOP for the handling and storage of used oil to the Director by ***December 31, 2018***. The SOP shall include as a minimum, detail procedures for the storage, handling and recording of the volumes and quality of used oil.

Wastewater Flows and Treatment

41. The Thermal Generating Station's once-through cooling water shall be obtained from Indian Pond, and shall be discharged directly to Conception Bay.

42. The Thermal Generating Station's south-east floor drains shall be routed through an oil/water separator (OS-1) and then to Indian Pond through the storm water collection system.

43. The Thermal Generating Station's south-west floor drains shall be routed through a grease trap and an oil/water separator (OS-2) and then to the cooling water discharge piping associated with Unit No. 1 & 2.

44. The Thermal Generating Station's north-east and north-west floor drains shall be routed through a grease trap and oil/water separator (north-east OS-4 & north-west OS-3) and then to a 900 m^3 equalization basin (Continuous Basin).

45. All wastewater generated from backwashing in the Combustion Turbine water treatment plant from the backwashing shall be routed to the Combustion Turbine oil/water separator (CT-OS) prior to discharge into Indian Pond.

46. All oil/water separators shall be checked routinely to ensure they are working properly. A log of these checks shall be maintained.

47. Wastewater streams resulting from the Thermal Generating Station's daily operations, including raw water clarification, filter backwashes, boiler blowdown and other similar activities shall be directed to the Continuous Basin. Any flow or drainage from the Continuous Basin shall be routed to the new oil/water separator (OS-5) before discharging into Indian Pond.

48. Demineralizer regeneration wastewater flows may be directed to the seal pit associated with Units No. 1 & 2, during such times at least one cooling water pump shall be active.

49. Wastewater streams resulting from periodic events where water is used to clean the Thermal Generating Station's boiler fireside equipment, including air pre-heater wash flows, fireside boiler wash flows and boiler acid wash flows, shall be directed to a 900 m^3 equalization basin (Periodic Basin). Any flow or drainage from the Periodic Basin shall be directed to the wastewater treatment plant.

50. Any flow or drainage from the wastewater treatment plant shall be discharged to the cooling water intakes for Units No. 1 & 2 or Unit 3.

51. Effluent from the dewatering of filter cake shall be re-cycled through the wastewater treatment plant.

52. All solid waste generated from the Combustion Turbine water treatment plant and the Thermal Generating Station wastewater treatment plant operations shall be directed to the hazardous waste landfill.

Effluent Monitoring and Discharge

53. HYDRO shall perform an Effluent Monitoring Program as per Table 2. All results shall be submitted to the Director as per the ***Reporting*** section.

Table 2: Effluent Monitoring Program

Location	EDMS Location Code	Parameters	Frequency
WWTP	00068	Aluminum Iron Magnesium Nickel Vanadium pH TSS	Grab sample prior to each batch release †
		ALT	Grab sample from each batch following new addition of wastewater to the periodic basin
Continuous Basin Outfall	00069	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
		ALT	Monthly Grab
OS-1	00070	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
OS-2	00071	Iron Nickel Vanadium pH TSS TPH	Weekly Grab
CT-OS (Prior to discharge into Indian Pond)	00072	TPH TDS TSS BOD pH	Weekly (Whenever there is discharge)
† Grab samples for all parameters shall be taken from the batch reactor at the same time.			

54. If effluent from wastewater treatment plant fails the ALT, HYDRO shall collect a grab sample from the next batch of effluent from the wastewater treatment plant and conduct an ALT, even if there has been no addition to the Periodic Basin.

55. HYDRO shall record on a continuous basis the volume of influent to the Periodic Basin. The results shall be submitted to the Director as per the ***Reporting*** section.

56. Refer to Table 3 for the discharge criteria.

Table 3 - Effluent Discharge Criteria	
Parameter	**Allowable Limits ***
Arsenic	0.50
Barium	5.00
Boron	5.00
BOD	20.00
Cadmium	0.05
Chromium	1.00
Copper	0.30
Iron	10.00
Lead	0.20
Mercury	0.005
Nitrates	10.00
Nitrogen (ammoniacal)	2.00
Nickel	0.50
Phenol	0.10
Phosphates (total as P2O5)	1.00
pH	5.5 – 9.0 pH units
Selenium	0.01
Silver	0.05
TDS	1000.00
TSS	30.00
TPH	15.00
Vanadium	0.50
Zinc	0.50
* Units are in mg/L unless otherwise specified	

57. If effluent is determined to be acutely lethal for three consecutive ALTs, HYDRO shall implement a toxicity identification evaluation to identify the toxin, and from this develop measures to prevent or reduce the toxin. The report, written as a result of these identification activities, shall be submitted to the Director for review, ***within 60 days*** of the third consecutive failed ALT result. After review of the report, the Director may place additional requirements upon the proponent for treatment of effluent prior to discharge.

Water Chemistry Analysis

58. HYDRO shall perform a Water Chemistry Analysis Program for the Thermal Generating Station four times per calendar year and not less than thirty (30) days

apart, as per Table 4. All results shall be submitted to the Director as per the ***Reporting*** section.

59. HYDRO shall perform a Water Chemistry Analysis Program for the Combustion Turbine on a monthly basis, whenever the Combustion Turbine water treatment plant and/or Combustion Turbine is in operation, as per Table 4. All results shall be submitted to the Director as per the ***Reporting*** section.

<table>
<tr><th colspan="3">Table 4 - Water Chemistry Analysis Program</th></tr>
<tr><th>Location</th><th>EDMS Location Code</th><th>Parameters</th></tr>
<tr><td>Cooling Water Intake at Indian Pond (Grab Sample)</td><td>00073</td><td rowspan="2">**General Parameters** – must include the following:

nitrate + nitrite, colour, magnesium, reactive silica
nitrate, TDS (calculated), sodium, alkalinity
nitrite, orthophosphate, phenolics, ammonia
pH, potassium, sulfate, phosphorous
TSS, carbonate ($CaCO_3$), calcium, chloride
DOC, hardness ($CaCO_3$), sulphide, turbidity
conductance, bicarbonate ($CaCO_3$)</td></tr>
<tr><td>Cooling Water Outfall Stream, Prior to Release into Conception Bay (Grab Sample)</td><td>00074</td></tr>
<tr><td>Continuous Basin Outfall Stream, Prior to Release into Indian Pond (Grab Sample)</td><td>00069</td><td rowspan="2">**Metals Scan** - must include the following:

Aluminium, boron, iron, nickel, tin
antimony, cadmium, lead, selenium, titanium
arsenic, chromium, manganese, silver, uranium
barium, cobalt, molybdenum, strontium, vanadium
beryllium, copper, mercury, thallium, zinc
bismuth</td></tr>
<tr><td>CT Effluent Prior to Discharge into Indian Pond</td><td>00072</td></tr>
</table>

60. HYDRO shall inform the Department of the date and duration of any usage of the **Copper Ion Injection** in their system, as per ***Reporting Section***.

Environmental Effects Monitoring

61. HYDRO shall continue to conduct an Environmental Effects Monitoring study to monitor the impacts of the discharge of cooling water, the continuous basin's water and the wastewater treatment plant treated water on Conception Bay. The study design shall be submitted to the Director for review by ***September 30, 2017.*** The results of the completed study shall be submitted to the Director for review by ***June 30, 2020.***

Hazardous Waste Landfill Operations

62. HYDRO shall operate the hazardous waste landfill in the manner as described in the ***Landfill Operations Manual.*** Any revision or changes to the ***Landfill Operations Manual*** shall be submitted to the Director for review and approval prior to such revision or changes being made.

63. Only waste identified in the ***Landfill Operations Manual*** shall be placed in the hazardous waste landfill. These include: bottom and fly ash, periodic basin sludge, continuous basin sludge, wastewater treatment plant filter-cake, filter sand, raw-water treatment ion exchange resins, and clean-up from chemical spills.

64. Liquid waste shall not be disposed of in the hazardous waste landfill, unless otherwise authorized in writing by the Department.

65. The Department reserves the right to require some form of pre-treatment of waste before placement in the site.

66. HYDRO shall periodically review opportunities for reuse and/or recycling of the waste types disposed of in the landfill.

67. HYDRO shall maintain a landfill security fence with a sign affixed to the fence identifying the site as a hazardous waste containment system. This sign shall identify the owner of the landfill and a contact phone number. The sign and its placement shall be acceptable to the Department.

68. No activities shall occur within the fenced area of the landfill, except for the deposition of waste; extraction of leachate; or other maintenance requirements of the landfill cap or the landfill.

69. HYDRO shall conduct an annual inspection program as per the ***Landfill Operations Manual.***

70. Leachate accumulated in each of the hazardous waste landfill collection systems, including the leachate holding pond, shall be removed as required so that leachate does not overflow the collection system.

71. Any flow or drainage from the leachate holding pond shall be directed to the Periodic Basin. Leachate shall not be discharged directly to the environment without prior authorization by the Department.

Hazardous Waste Landfill Monitoring

72. HYDRO shall perform an Environmental Monitoring Program as depicted in the ***Landfill Operations Manual,*** including monitoring of: groundwater quality and levels, surface water quality, leachate leakage, liner integrity and physical movement of the landfill.

73. HYDRO shall perform a Groundwater Monitoring Program as per Table 5. This monitoring program shall be performed throughout the operational life of the landfill, and during the twenty five (25) years following closure.

Table 5: Groundwater Monitoring Program			
Location	**EDMS Location Code**	**Parameters**	**Frequency**
Monitoring Wells: BH-1 BH-2 BH-3 BH-4 BH-5 BH-6 BH-7	 00075 00076 00077 00078 00079 00080 00081	Aluminum Iron Magnesium Nickel Vanadium	**Every Four Months**
Monitoring Wells: BH-1 BH-2 BH-3 BH-4 BH-5 BH-6 BH-7	 00075 00076 00077 00078 00079 00080 00081	Antimony Arsenic Barium Beryllium Bismuth Cadmium Cobalt Calcium pH Chromium Copper Lead Manganese Mercury Molybdenum Phosphorus Potassium Selenium Silver Sodium Zinc VOC's TDS	**Annually**

74. HYDRO shall perform a Surface Water Monitoring Program as per Table 6. This monitoring program shall be performed throughout the operational life of the landfill, and during the twenty five (25) years following closure.

Table 6: Surface Water Monitoring Program			
Location	**EDMS Location Code**	**Parameters**	**Frequency**
Surface Well 1	00082	VOCs	**Annually**
Surface Well 2 Surface Well 3 Surface Well 4 Surface Well 5 Surface Well 6 .	00083 00084 00085 00086 00087	Cadmium Chromium (total) Iron Lead Mercury Nickel Vanadium pH TDS TSS	**Monthly (provided water is flowing in the ditches during the month)**

75. The total monthly flow:

- from the primary and secondary leachate collection systems;
- from the leachate holding pond to the Periodic Basin; and

- through the primary cell and holding pond leak detection manholes;

shall be accurately measured and recorded. This record and all results from the Groundwater and Surface Water Monitoring Programs shall be submitted to the Director as per the ***Reporting*** section.

76. HYDRO shall submit an annual Landfill Operating Report to the Director by ***February 28*** of the subsequent year. This report shall include:

- results of the Environmental Monitoring Program; and
- summaries of all materials placed in the landfill site including: waste characterization reports, volumes of waste deposited in the landfill, source(s) of the waste, identification of contaminants of concern, and copies of the hazardous waste manifest forms.

Ambient Air

77. HYDRO shall operate an ambient air monitoring program as per the conditions in this Approval and its amendments. Approval shall be obtained from the Director prior to purchase or installation of any monitoring equipment.

78. Site locations and parameters to be monitored are outlined in Table 7.

Table 7 - Ambient Air Monitoring Program	
Monitoring Sites	**Parameter**
Butter Pot	$PM_{2.5}$, SO_2, NO_x, NO_2
Green Acres	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Indian Pond	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Lawrence Pond	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Lower Indian Pond Drive	TSP, $PM_{2.5}$, SO_2, NO_x, NO_2
Main Gate	TSP, $PM_{2.5}$

79. HYDRO shall label, date and store all the TSP filters from the monitoring sites in a secure place for the period of three (3) month.

80. Ambient air monitoring shall be done in accordance with the ***Ambient Air Monitoring Guidance Document (GD-PPD-065)***, or its successors.

81. Frequency of non-continuous TSP sampling shall coincide with the 6-day National Air Pollution Surveillance (NAPS) schedule. Sampling results shall be submitted as per the ***Reporting*** section.

82. Non-continuous TSP shall be determined by the United States EPA Test Method: "Reference Method for the Determination of Suspended Particulate Matter in the Atmosphere (High-Volume Method), or alternate method approved by the Director.

83. HYDRO shall operate, calibrate and maintain a meteorological station at **Green Acres** site in accordance with the guidelines specified in the United States EPA document "Quality Assurance Handbook for Air Pollution Measurement Systems -

Volume IV: Meteorological Measurements Version 2.0 (Final)," EPA- 454/B-08-002, or its successors. Parameters to be measured and recorded shall include as a minimum: wind speed, wind direction, ambient air temperature, relative humidity, barometric pressure and precipitation. All records shall be made available to the Department upon request.

84. Information regarding calibrations, site visits and maintenance for all continuous ambient air monitors shall be recorded into the DR DAS electronic logbook. Specific information regarding non-continuous TSP monitors, including but not limited to slopes, intercepts, initial and final masses, times, flows, etc. shall be submitted electronically, as per the ***Reporting*** section.

Continuous Opacity Monitoring System

85. Opacity of emissions from each boiler at the Thermal Generating Station shall be continuously measured and recorded using a Continuous Opacity Monitoring System (COMS) that meets all the requirements of *Performance Specification 1 (PS-1) - Specifications and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources,* of the United States *Code of Federal Regulations - 40 CFR Part 60, Appendix B*. Minimum QA/QC requirements are specified to assess the quality of COMS performance. Daily zero and span checks, quarterly performance audits, and annual zero alignment checks are required to assure the proper functioning of the COMS and the accuracy of the COMS data. These shall be recorded in a written log and a copy made available on request.

86. The United States EPA Federal Register Test Method 203 - Determination of the Opacity of Emissions from Stationary Sources by Continuous Opacity Monitoring Systems shall be used to determine compliance with the opacity standards in the ***Air Pollution Control Regulations, 2004.***

87. Monthly opacity data reports, in digital format, shall be submitted in the form of six minute arithmetic averages of instantaneous readings, as per the ***Reporting*** section. Each six minute average data point shall be identified by date, time and average percent opacity.

Continuous Emissions Monitoring System

88. Emissions from each boiler at the Thermal Generating Station shall be measured and recorded using an automated CEMS that meets the requirements of Environment Canada's *Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation (EPS 1/PG/7)*, or its successor. Notwithstanding this, application of specific requirements of EPS 1/PG/7 to the CEMS may be modified subject to approval by the Director.

89. Monthly CEMS data reports containing one-hour arithmetic averages of emission rates of SO_2, NO_x, CO_2, CO and O_2 (all expressed in ppmv) shall be submitted in digital format, as per the ***Reporting*** section.

Pollution Control Equipment

90. All pollution control equipment shall be maintained and operated as per manufacturer's specifications for best performance.

91. HYDRO shall not operate the Combustion Turbine unless the NOx control system associated with the Combustion Turbine is in full operation.

Administrative boundary

92. The ambient air quality standards specified in Schedule A of the ***Air Pollution Control Regulations, 2004*** shall apply to all points outside of HYDRO's administrative boundary. The administrative boundary is defined as the area encompassed by the coordinates contained in Appendix B, a total area of approximately **0.2687 km²**. All coordinates are referenced to NAD83 UTM Zone 22.

Stack Emissions Testing and Dispersion Modelling

93. Stack emissions testing shall be done in accordance with the ***Stack Emission Testing Guidance Document (GD-PPD-016.1)***. Dispersion modelling shall be done in accordance with the ***Plume Dispersion Modelling Guidance Document (GD-PPD-019.2)***. Determination of frequency of stack emissions testing and dispersion modelling shall be done in accordance with the ***Compliance Determination Guidance Document (GD-PPD-009.4)***.

94. HYDRO shall be required to complete the next stack emissions testing once every four years if it has been shown, via a registered dispersion model, that the operation is in compliance with section 3(2) and Schedule A of the ***Air Pollution Control Regulations, 2004***. If it has been shown, via a registered dispersion model, that the operation is not in compliance with section 3(2) and Schedule A of the ***Air Pollution Control Regulations, 2004***, then the facility shall complete stack emissions testing every two years.

95. Plume dispersion modelling results shall be submitted to the Department within ***120 days*** of completion of the stack emissions testing.

Annual Air Emissions Reporting

96. HYDRO shall submit an annual Air Emission Report to the Director by ***February 28*** of the subsequent year. This report shall include:

- total fuel consumption;
- the weighted average sulfur content of the fuel;
- the fuel specific gravity;
- the estimated, or, if available, the monitored annual emissions of the following flue gas constituents: SO_2, NO_x, NO_2, CO and particulate; and
- the actual calculations including factors, formulae and/or assumptions used.

Analysis and QA/QC

97. Unless otherwise stated herein, all solids and liquids analysis performed pursuant to this Approval shall be done by either a contracted commercial laboratory or an in-house laboratory. Contracted commercial laboratories shall have a recognized form of accreditation. In-house laboratories have the option of either obtaining accreditation or submitting to an annual inspection by a representative of the Department, for which HYDRO shall be billed for each laboratory inspection in accordance with Schedule 1 of the ***Accredited Laboratory Policy (PD:PP2001-01.02)***. Recommendations of the Director stemming from the annual inspections shall be addressed within 6 months, otherwise further analytical results shall not be accepted by the Director.

98. If HYDRO wishes to perform in-house laboratory testing and submit to an annual inspection by the Department then a recognized form of proficiency testing recognition shall be obtained for compliance parameters for which this recognition exists. The compliance parameters are listed in the ***Effluent and Monitoring*** section. If using a commercial laboratory, HYDRO shall contact that commercial laboratory to determine and to implement the sampling and transportation QA/QC requirements for those activities.

99. The exact location of each sampling point shall remain consistent over the life of the monitoring programs, unless otherwise approved by the Director. A sketch or diagram clearly identifying each sampling location shall be submitted by ***March 31, 2017*** to the Department.

100. HYDRO shall bear all expenses incurred in carrying out the environmental monitoring and analysis required under conditions of this Approval.

Monitoring Alteration

101. The Director has the authority to alter monitoring programs or require additional testing at any time when:

- pollutants might be released to the surrounding environment without being detected;
- an adverse environmental effect may occur; or
- it is no longer necessary to maintain the current frequency of sampling and/or the monitoring of parameters.

102. HYDRO may, at any time, request that monitoring programs or requirements of this Approval be altered by:

- requesting the change in writing to the Director; and
- providing sufficient justification, as determined by the Director.

The requirements of this Approval shall remain in effect until altered, in writing, by the Director.

Reporting

103. Monthly reports containing the environmental compliance monitoring and sampling

information required in this Approval shall be received by the Director in digital format within 30 calendar days of the reporting month. All related laboratory reports shall be submitted with the monthly report in XML format and Adobe Portable Document Format (PDF). Digital report submissions shall be uploaded through the EDMS web portal. The Pollution Prevention Division shall provide details of the portal web address and submission requirements.

104. Each monthly report shall include a summary of all environmental monitoring components and shall include an explanation for the omission of any requisite data. The monthly summary reports shall be in Microsoft Word or Adobe PDF and shall be uploaded through the EDMS web portal with the data submissions

105. All incidents of:

- *Contingency Plan* implementation; or
- non-conformance of any condition within this Approval; or
- spillage or leakage of a regulated substance; or
- discharge criteria being, or suspected of being, exceeded; or
- verbal/written complaints of an environmental nature from the public received by HYDRO related to the Thermal Generating Station, whether or not they are received anonymously;

shall be immediately reported, within one working day, to Department.

A written report including a detailed description of the incident, summary of contributing factors, and an Action Plan to prevent future incidents of a similar nature, shall be submitted to the Department. The Action Plan shall include a description of actions already taken and future actions to be implemented, and shall be submitted within thirty days of the date of the initial incident.

106. Any spillage or leakage of gasoline or associated product shall be reported immediately through the Canadian Coast Guard at 1-(709)-772-2083.

Liaison Committee

107. The Department recognizes the benefits, and at times the necessity, of accurate, unbiased communication between the public and industrial operations, which have an impact on the properties and residents in the area. The Department encourages the formation and regular meeting of a Liaison Committee comprised of representatives of HYDRO, the Department and independent members of the general population of Holyrood and Conception Bay South. Regular meetings of the Liaison Committee will provide a clear conduit of communication between concerned citizens and HYDRO.

Expiration

108. This Certificate of Approval expires ***August 31, 2021.***

109. Should HYDRO wish to continue to operate the Thermal Generating Station and the Combustion Turbine beyond this expiry date, a written request shall be submitted to the Director for the renewal of this Approval. Such request shall be made prior to ***March 1, 2021.***

APPENDIX A

Industrial Site Decommissioning and Restoration Plan Guidelines

As part of the Department of Environment and Climate Change's ongoing commitment to minimize the residual impact of industrial activities on the environment of the province, the Department requires that HYDRO shall develop a Decommissioning and Restoration Plan for the Thermal Generating Station at Holyrood, NL and its associated property. The guidelines listed below are intended to provide some general guidance as to the expectations of the Department with regard to the development of the Plan, and to identify areas that are of particular concern or interest. The points presented are for consideration, and are open to interpretation and discussion.

Decommissioning and Restoration Plans are intended to present the scope of activities that a company shall undertake at the time of final closure and/or decommissioning of the industrial properties. Where it is useful and practical to do so the company is encouraged to begin undertaking some of the activities outlined in the Plan prior to final closure and decommissioning. The objectives of the restoration work to be undertaken can be summarized as follows:

- to ensure that abandoned industrial facilities do not endanger public health or safety;
- to prevent progressive degradation and to enhance the natural recovery of areas affected by industrial activities;
- to ensure that industrial facilities and associated wastes are abandoned in a manner that will minimize the requirement for long term maintenance and monitoring;
- to mitigate, and if possible prevent, the continued loadings of contaminants and wastes to the environment. The primary objective shall be to prevent the release of contaminants into the environment. Where prevention is not practical due to technical or economic limitations then activities intended to mitigate the consequence of such a release of contaminants shall become the objective of restoration work;
- to return affected areas to a state compatible with the original undisturbed condition, giving due consideration to practical factors including economics, aesthetics, future productivity and future use; and
- to plan new facilities so as to facilitate eventual rehabilitation.

The Decommissioning and Restoration Plan should:

- identify areas of known historical or current contamination;
- identify past or existing operational procedures and waste management practices that have, or may have, resulted in site contamination;
- highlight the issues or components to be addressed;
- identify operational procedures and waste management practices that can prevent or reduce site contamination;
- consider future land use, regulatory concerns and public concerns;
- enable estimation of the resources and time frame required to decommission the facility and restore the site to a condition acceptable to the Department;
- enable financial planning to ensure the necessary funds for decommissioning and restoration are set aside during the operational life of the facility, and;
- include arrangements for appropriate project management to ensure successful completion of the decommissioning and restoration program.

APPENDIX B

HYDRO Administrative Boundary Coordinates

341903.0	5257750.4
341925.9	5257759.4
341972.8	5257727.0
341962.6	5257711.0
342036.6	5257660.9
342232.8	5257494.1
342162.6	5257271.8
342095.8	5257245.3
341947.8	5257207.3
341949.6	5257201.9
341957.0	5257196.4
341949.3	5257185.4
341926.5	5257202.1
341918.4	5257200.3
341700.2	5257177.4
341694.0	5257177.7
341659.1	5257166.3
341593.5	5257072.8
341563.4	5257088.4
341513.5	5257117.4
341528.6	5257149.4
341509.6	5257158.7
341544.1	5257250.4
341563.9	5257298.8
341571.2	5257314.4
341584.6	5257339.8
341612.8	5257383.6
341662.4	5257454.4
341685.8	5257484.8
341704.4	5257507.1
341748.2	5257599.8
341750.0	5257614.9
341756.9	5257644.8
341770.7	5257678.4
341789.5	5257710.2
341844.4	5257789.4
341903.0	5257750.4

Cc: Mr. Neil Codner
Environment and Climate Change Canada
6 Bruce Street
Mount Pearl, NL
A1N 4T3

Mr. Robert Locke
Manager of Operations and Environmental Protection
Service NL
5 Mews Place
P.O. Box 8700
St. John's, NL
A1B 4J6

Chief Administrative Officer
Town of Holyrood
P.O. Box 100
Holyrood, NL
A1B 4J6

Chief Administrative Officer
Town of Conception Bay South
P.O. Box 280
CBS, NL
A1W 1M8

ASSESSMENT OF VIABILITY OF CONTINUED OPERATION OF HOLYROOD THERMAL GENERATION STATION AS A BACKUP FACILITY

August 2020

ASSESSMENT OF VIABILITY OF CONTINUED OPERATION OF HOLYROOD THERMAL GENERATION STATION AS A BACKUP FACILITY

Prepared for:

Newfoundland & Labrador Hydro
500 Columbus Drive
St. John's, NL A1B 3T5

Prepared by:

Wood Canada Limited
133 Crosbie Road
St. John's, NL AIA 3C1

REGISTERED PROFESSIONAL ENGINEER
BLAIR R. SECKINGTON
Blair Seckington
SIGNATURE
Sept 28/2020
DATE
NEWFOUNDLAND & LABRADOR

PROVINCE OF NEWFOUNDLAND AND LABRADOR
pegnl
ENGINEERING PERMIT D0018
Wood Canada Limited
Signature or Member Number
(Member-in-Responsible Charge)

REV.	DATE	REVISION(S)	PREPARED BY	CHECK	APP	CLIENT
0	28-Sep-20	Issued for Use	IL	BS	RH	
E	18-Sep-20	Reissued for Client Review	IL	BS	RH	
D	28-Aug-20	Reissued for Client Review	IL	BS	RH	
C	26-Aug-20	Reissued for Client Review	IL	BS	RH	
B	21-Aug-20	Reissued for Client Review	IL	BS	RH	
A	7-Aug-20	Issued for Client Review	IL	BS	RH	

wood.	Assessment of Viability of Continued Operation of Holyrood Thermal Generation Station as a Backup Facility	Wood Canada Limited Job No. 205882
		205882-001-CD10-RPT-002 REV. 0
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IMPORTANT NOTICE

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Appendices

Executive Summary

As part of its ongoing Reliability and Resource Adequacy study, Newfoundland and Labrador Hydro (NLH) is assessing the technical and economic viability of maintaining the Holyrood Thermal Generating Station (HTGS) as a backup facility for the Island Interconnected System. This report evaluated the following three issues that are currently considered limitations and makes recommendations to improve operational performance. Based on this evaluation, Wood recommends that HTGS can technically fulfil the role of backup facility.

NLH will use findings from this exercise as preliminary insight as to whether it is economically feasible to modify HTGS to become a suitable backup facility and thus be considered as a resource option in NLH assessments.

Minimum Load

An improvement to the historical minimum load of 70 MW per unit was demonstrated in June 2020 through a series of tests on Unit 2 that proved that a minimum load of 30 MW is achievable. Operational changes, further trials and optimization on all units and an observational minimum-load operating period are necessary prior to reliable operation at the new minimum load.

Faster Start Times

HTGS units are normally started from cold in two-to-three days. This can be, and has been demonstrated to be, shortened to under twelve hours. Engineering, investment and testing are required to ensure reliable fast starts of cold units. The essential recommendations are using Unit 3 boiler to provide auxiliary steam when the plant is not generating but may be called upon, installing Flue Gas Temperature (FGT) monitoring, and installing day fuel tank recirculation and heating. Additional recommendations are provided to prepare for cold starts and prevent trips during the start process. The capital cost (+100% / -25%) of the essential recommendations is estimated to be $0.4M and the remaining recommendations is estimated to be $1.1M.

Synchronous Condenser to Generation Conversion Time

Unit 3 can operate as a synchronous condenser by uncoupling the generator and turbine. The conversion from synchronous condenser to generator currently takes five-to-seven days, four days of which is a complex process of purging hydrogen from the generator. A new work procedure is currently being developed to safely complete this uncoupling/recoupling without purging in two-to-three days. Such procedures have been used elsewhere in Canada.

1. Introduction

As part of its ongoing Reliability and Resource Adequacy study, NLH is assessing the technical and economic viability of maintaining HTGS as a backup facility for the Island Interconnected System. Wood was contracted by NLH to assess the technical viability of HTGS to act as a reliable source of emergency power to the Newfoundland grid in the event of an outage to the Labrador Island Link (LIL). Three specific issues are addressed from a technical perspective in this assessment of viability:

- Can the minimum load at which the units operate be reduced?
- Can the units start from cold faster?
- Can the conversion time from synchronous condenser to generator be reduced?

In this report, the backgrounds of each of these issues are examined, recommendations are made to improve upon the current situation, and high-level cost implications are explained.

Wood is a global leader in the delivery of project, engineering and technical services to energy and industrial markets with operations in more than 60 countries. Wood is very familiar with operations at HTGS and has completed the following major assignments at the HTGS:

- 2010/11 Holyrood Level 1 Condition Assessment – Major EPRI Level 1 assessment of all HTGS equipment and systems which identified recommended remaining lives, suggested capital investments, and additional detailed EPRI Level 2 assessments.
- 2012-15 Holyrood Level 2 Condition Assessments – Carried out by Wood (AMEC NSS).
- 2017 Holyrood Condition Assessment Update – Major EPRI Level 1 assessment of all HTGS equipment and systems.
- 2019 Holyrood Thermal Generating Station Condition Assessment & Life Extension Study. An extensive review and confirmation of capital plans, operating costs and staffing levels necessary for the continued operations of the plant to March 2023 and standby operations of Unit 1 and Unit 2 to March 2027

2. Acronyms

The following acronyms have been used throughout this document:

ABNFS	Available But Not Fully Staffed
ABNO	Available But Not Operating
AC	Alternating Current
CO_2	Carbon Dioxide Gas
CV	Control Valve
DC	Direct Current
DCS	Distributed Control System
ECC	Energy Control Centre
EPRI	Electric Power Research Institute
FGT	Flue Gas Temperature
GE	General Electric
H_2	Hydrogen Gas
HP	High Pressure
HTGS	Holyrood Thermal Generating Station
IP	Intermediate Pressure
kPa	KiloPascals
LCP	Lower Churchill Project
LIL	Labrador Island Link
LP	Low Pressure
MPa	MegaPascals
MW	MegaWatts
NLSO	Newfoundland and Labrador System Operator
NLH	Newfoundland and Labrador Hydro
OEM	Original Equipment Manufacturer
RPM	Revolutions per Minute
RPP	Resource and Production Planning
TRO	Transmission and Rural Operations

3. References

The following documents have been referenced during the compilation of this report.

General Electric Start-up and Loading Manual

Combustion Fossil Power, 1991 Edition

4. Background

HTGS is a three-unit, heavy oil-fired steam cycle generating station on the south shore of Conception Bay in Newfoundland and Labrador. HTGS has a nominal capacity of 490 MW (net) and was constructed in two stages: Units 1 & 2 in the late 1960's and Unit 3 in 1977. Units 1 & 2 were modified in 1987 to increase their capacity to 170 MW (net) each; Unit 3 is 150 MW capacity. Typically, the units operate late Fall through Spring to support the Winter electrical demand peak. HTGS has served as a seasonal baseload station with hydroelectric generators elsewhere on the island of Newfoundland providing Winter peak capacity and most spinning reserve capacity. Given the proximity to the largest load centre, North-East Avalon, HTGS Unit 3 operates as a synchronous condenser for grid voltage support during the Summer season.

As a seasonal baseload generating station, the primary mandate was to provide high reliability during the Winter readiness season at minimal cost. Historically, the units did not operate below 70 MW capacity each due to concerns that long-term reliability would be affected. With the current interest in changing the HTGS mandate to backup power, there are opportunities and justification to further explore lower minimum loads. Similarly, it is desirable to reduce unit start-up time from the current two-to-three day time frame.

Conversion of Unit 3 from generator to synchronous condenser operation requires decoupling the turbine and generator, and reinstating generation requires recoupling turbine and generator. The current work method used requires five-to-seven days to transition from one state of operation to another. Unit 3 currently operates as a synchronous condenser during the Summer and will likely operate as such year-round to support the LIL electrical infeed to the island.

5. Viability of Reducing Minimum Load

NLH and Wood agreed that a target sustained minimum load of 30 MW should be achievable. It is not uncommon for turbines of similar vintage to be able to operate at 25% capacity. Four test procedures were developed by Wood and executed by HTGS operations staff in June 2020 with the goal of finding out which of the test conditions best suited both the boiler and the turbine while maintaining the ability to reload the unit quickly if requested by Energy Control Centre (ECC). Due to Summer outages, all tests were carried out on Unit 2. Since Unit 1 is of the same manufacturer and the same design, it can be assumed that outcomes will be similar to Unit 2. Individual units may have unique minimum loads and over time these loads may vary by a few megawatts due to the operational characteristics of the individual unit. Testing of Unit 3, which has different Original Equipment Manufacturers (OEM's) for the turbine/generator and the boiler than Units 1 & 2, should be undertaken at earliest opportunity to determine which setup method should be employed. Testing of Unit 3 is expected to result in similar results as Units 1 & 2, but this should be confirmed.

Several parameters (see Appendix A) were monitored and recorded during these tests to ensure that the unit operated safely and within OEM guidelines over extended periods of time. With the intent to operate these units at the safest lowest possible minimum load, Unit 2 was never placed in jeopardy. Any system alarm received during the test deemed to be a threat to the safety and security of the unit would have caused cancellation of the test; HTGS indicated that no such alarms were received.

A Wood Operations Specialist was unable to directly oversee the tests because of Covid-19 pandemic travel restrictions but was in regular communications with HTGS Operations during the tests. Based on the results obtained and previous operating knowledge, Wood Operations Specialist has determined operating HTGS units at a sustained 30 MW minimum load is acceptable if recommended procedures are followed, further trials conducted for refining purposes, and recommended upgrades implemented.

5.1 Minimum Load Test Plans

Four test plans were submitted to HTGS Operations to gradually reduce load on the unit from 70 MW to 30 MW while collecting operating information from the Distributed Control System (DCS). These tests were to be carried out with the understanding that if operating limits were being exceeded the test was to be terminated. Details of the test plans are included in Appendix B.

1. Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine
2. Partial Sliding Pressure Partial Control Valve (CV) Closure to Achieve Minimum Load of 30 MW
3. Total Variable Pressure Drop from Design Pressure to 30 MW
4. Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

5.2 Results of Minimum Load Tests

The following is an overview of the different tests conducted by HTGS Operational personnel:

Test Method 1: Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine

Results indicate that the unit could operate at 30 MW using this method. However, the results provided indicate that the unit was at that load for a very short time. If the unit had held 30 MW for the six-hour time frame, it is expected that the High Pressure (HP) Turbine 1st Stage Inner and Outer Metal Temperatures would have dropped significantly and subsequently caused high stress values when reloading the unit. This has been the experience of Wood Operations Specialist and is also stated in the General Electric (GE) Turbine Starting and Loading Manual.

Test Method 2: Partial Sliding Pressure Partial CV Closure to Achieve Minimum Load of 30 MW

Lowering the HP Turbine Throttle Pressure down to 11 MPa from the design pressure reduced the generator load to 61 MW. Using the CV's to lower the generator load to 30 MW and holding that load for six hours caused a slight but acceptable reduction of temperatures in the HP Turbine 1st Stage. The 1st Stage temperatures dropped from 432°C down to 383°C at 30 MW. Reloading the unit should not have caused any major heat stress event. However, one concern that was observed revolves around the Reheat Bowl Inner Metal Temperatures (likely due to a known probe accuracy issue). The inner metal temperature of the Reheat Bowl remained extremely low during the whole test. This was observed when the unit was at 70 MW at the design steam pressure and steam temperatures. Readings of 138°C were recorded and stayed at that level during the entire test. The Hot Reheat Steam temperature remained around 470°C and the Outer Reheat Bowl Metal Temperature indicated a temperature as high as 488°C at 30 MW. The outer temperature appears to be reasonable due to the overall thickness of this section along with the temperature of the Hot Reheat Steam as it will take a much longer time to cool. The anomaly with the Reheat Bowl Inner Metal temperature needs to be investigated further at the station to determine the cause. Lowering the unit load using this method caused some minor boiler control issues that could be addressed with boiler tuning and further trials.

Test Method 3: Total Variable Pressure Drop from Design Pressure to 30 MW

As expected, the HP Turbine 1st Stage Metal Temperatures and Reheat Bowl temperatures rose slightly from those at 70 MW as HP Turbine Throttle Pressure was reduced until 30 MW was reached. This was due to the fact the Main Steam Temperatures rose slightly along with the Hot Reheat Steam Temperature. Some concerns arose from this test.

- The turbine differential expansion increased from 4.35 millimetres to 7.72 millimetres which might be explained by the slightly higher metal temperatures.
- The boiler pressure must be lowered significantly to reach the desired load. Operating at these low pressures could create grid security issues if another generator on the island was to trip unexpectedly. HTGS units would attempt to restore the lost load which would cause the boiler steam drum pressure to drop even further and trip the unit due to high water levels in the steam drum.
- The Steam Drum Pressure is extremely low. Holding the new minimum load over long periods with just over 5 MPa pressure would result in the steam temperatures through the superheater and reheater tubes increasing to the point of requiring attemperation.

Test Method 4: Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

This test did not proceed as planned due to turbine control logic limitations. According to HTGS Operations, the transfer of load control to main steam stop valve bypass is much lower than the test plan during a normal shutdown and hence this part of the test could not be completed. Instead, a test was conducted during start-up from off-line using normal start-up procedure. The Main Steam Stop Valve and Bypass were used to run the unit up to synchronous speed, the unit synchronized to the grid, and HP Turbine Throttle pressure raised to 11.5 MPa to provide 30 MW. With the HP Throttle Pressure at 11.55 MPa, as time progressed, it was noted that the Turbine Metals temperatures improved, except for the Reheat Bowl Inner metal temperature. If the test had continued, it is expected that all of the temperatures would have stabilized near normal operating values. Concern still exists as to why the Reheat Bowl Inner metal temperature was not climbing like the rest of the unit and should be examined further. Whether this was due to a faulty thermocouple or reheat bowl drains being open unnecessarily is to be determined.

Test Method 4 sequence would have been GE normal operating procedure for coming down to minimum load when the station was first constructed. The reason GE has for this full arc admission type of operation was to ensure that chilling of the turbine metals did not occur thereby reducing the life cycle stress events the turbine would be subjected to. GE recommends the unit not be operated using the control valves below the transfer point for any longer than 5 minutes. The Main Stop Valve and Bypass are designed to deliver 20% of the total steam flow which equates to roughly 30 MW and the transfer point should be at a load slightly higher.

5.3 Recommendations to Reduce Minimum Load

Based on our review and recent testing conducted, the following actions are recommended.

1. Test Method 1, although feasible, is recommended by neither Wood nor the Turbine OEM. GE suggests that the unit should not be run in this manner for any longer than five minutes. What the definition of low loads is may be subject to interpretation but adding huge pressure differentials across the CVs and the turbine nozzle block may cause damage over time. Chilling of the HP Turbine metals would also occur over extended operating time at these loads. The pressure drop across the CVs would be increased such that the pressure downstream of the valves is reduced causing a cooling of the main steam and consequently the metal temperatures will drop.
2. Test Method 3 is not recommended for the reasons mentioned above with respect to grid security, higher than design reheat steam temperatures, and increased possibility of tube thinning and fractures of superheater, reheater, and economizer boiler tubes due to reduced cooling in these areas while operating at the lower steam flow rates.
3. A combination of Test Methods 2 & 4 should be further developed with the recommended upgrades and used to accomplish the 30 MW goal for minimum load. By reducing the HP Throttle Pressure to 11 MPa, transferring control from partial arc admission to full arc admission, and using the Main Steam Stop Valve and Bypass as the steam flow control, the unit is able to sit at or at least return to normal operating temperatures, therefore not risk high temperature stressing in the HP Turbine when the unit is requested to load. This is consistent with the GE Start-up and Loading Manual.
4. Further testing of all units should be conducted to optimize operating parameters and discern the differences of the individual units.
5. Logic changes are required in the turbine control system to change the transfer point from the Turbine Control Valves back to the Main Steam Stop Valve and Bypass. A higher value somewhere between 30 – 40 MW is necessary. The Boiler Control logic with respect to 3-element boiler feedwater control needs to be reconfigured to allow the controls to stay in automatic. The requirements to establish the 3-element control are a suitable feedwater flow, a suitable main steam flow input into the DCS, and a stable drum level. All these requirements can be met while operating below 30 MW therefore the controls should be tuned accordingly. Boiler tuning is also a necessity as the controls tuning needs to be tightened at the lower load. Controls Tuners tend not to worry about the tightness of the controls at loads where the unit is not expected to operate at for extended periods.

6. Wood recommends that NLH allow for a transition period between mandate of seasonal baseload generation and mandate of backup power during which HTGS units are operated at minimum load for a period while LIL is online. This will allow plant operators to learn the peculiarities of the new operating point, and plant engineering and maintenance personnel to identify any required changes to inspection and maintenance regimes or capital investment.

5.4 Budget Considerations

Operating Budget

Reducing minimum load from 70 MW to 30 MW reduces fuel consumption and greenhouse gas emissions while operating at that condition. A reduction of 65-75 bbl oil/hour/unit fuel consumption and 33-40 Mg/hour/unit CO_2 emissions is estimated. The costs to revise boiler and turbine control logic and re-tune boiler controls are a minimal one-time cost. Maintenance costs are not anticipated to increase noticeably due to the reduction in minimum load, but maintenance efforts will likely change areas of focus. Operating the plant during a transition period for observation purposes will consume fuel and require regular staffing even though there is no outage to LIL.

Capital Budget

There are no capital budget expenditures anticipated at this time. Investigation and engineering during the transition period may identify capital investment requirements to enhance reliability

6. Viability of Faster Starts

The target provided for fast starts was that the first unit called to start would synchronize in 8-12 hours, compared with 24-36 hours currently allotted. Common belief is that faster starts are achieved through external preheating of the turbines. However, through discussions with HTGS Operations, Wood holds the opinion that primary reasons for current long start times are boiler and fuel system related. On May 27, 2020 HTGS conducted a cold fast start test and synchronized the unit in just over nine hours without any additional turbine prewarming other than what is prescribed by the OEM. Industry standard for units of this size and vintage is eight-to-twelve hours, and Wood contend that should be regularly achievable for HTGS.

6.1 Definition of Faster Starts

Fast Starts can be defined differently depending on the condition of the Units Boiler, Turbine Generator and the associated equipment used in the operation of these major pieces of equipment. A start that is considered Cold is one where the boiler and turbine are at less than 100°C. This is considered as a Cold Start because the HP turbine requires to be prewarmed as prescribed by the OEM. Extreme stresses would be incurred if high temperature steam were introduced to a cold HP turbine therefore a slow heating procedure is followed before the unit is rolled on steam to reduce that concern. An achievable cold start time for a HTGS Unit with Nitrogen (N_2) filling of the boiler should be in the 6-12 hours range depending on the actual HP turbine metal temperature at the time of the start. For a turbine which is defined to be in a Warm Start condition, HP turbine inner metal temperatures between 100 - 325°C, a start time of 2.5 hours should be achievable. If the turbine HP turbine inner metal temperature is greater than 325°C (Hot Start) a start time of 1.5 hours can be achieved. All the above start times are based on the conditions of the unit boiler, turbine-generator, and the common systems necessary to run a unit.

- The auxiliary steam common header pressurized to 1.4 MPa from an auxiliary boiler or Unit 3 as an auxiliary steam source.
- The main fuel oil systems must be preheated and recirculated in order to be available to establish firing the boiler quickly and aggressively within the boiler manufacturers temperature limitations.
- The boiler temperature limitations along with a number of operational issues must be controlled during starts.
- The turbine-generator must be on turning gear for a minimum number of hours prior to rolling using steam. GE recommends 8 hours although shortening that time to as low as 4 hours has become an industry standard and is recommended by Wood. HTGS should conduct testing to determine the minimum time their units need to be on turning gear and adjust their procedures accordingly.

6.2 Unit Status

Available But Not Operating (ABNO)

ABNO may take on different meanings to different work groups. A unit that operated in the past three days and is still on turning gear, and a unit with boiler under layup procedure with N_2 filling can both be considered ABNO but will require different preparations for starting. Therefore, a strong understanding and a clear definition of an ABNO unit is required to ensure that the different work groups are all working to the same one when a fast start is requested. Because at least three different work groups are involved in this process, we believe that a definition needs to be developed by all interested parties: HTGS Operations; Newfoundland

and Labrador System Operator (NLSO); Resource and Production Planning (RPP); and Transmission and Rural Operations (TRO).

Available But Not Fully Staffed (ABNFS)

During extended non-operating times, a skeleton operating staff will be required in the plant 24/7 to ensure the equipment is in a state of readiness. A unit may be available to operate physically but if there is not sufficient experienced staff available to complete the start, then the start-up would be partially compromised until appropriate staff were present. This status was not previously used at HTGS but is particularly significant to whether the required start is an emergency or is planned.

6.3 Unit Pre-Conditions for a Cold Fast Start

A detailed listing of systems to be available and in service for a start is provided in Appendix C. This list assumes start up from a lay-up state and Wood is confident such a start can be accomplished safely and reliably within 12 hours provided the recommendations that follow are implemented. The lay-up state is intended to prevent corrosion and assumes N_2 filling of the steam spaces of the LP and HP Feedwater Heaters, including the Deaerator, and filling the water side of those heaters with treated demineralized water. Although the original equipment had capabilities for N_2 filling, Wood understands that some refurbishment will be required to ensure full functionality.

Three primary conditions must be met for fast cold starts to be realized:

- There can be no Outstanding Work Protection in place on the unit or in the switchyard that inhibits the start.
- Staff to operate the unit must be available in the plant or at least on call to respond if the start is of an emergency nature.
- Auxiliary steam must be available.

Provided all systems are available and primary conditions met, a cold start can commence. A generalized procedure for cold starts is provided in Appendix D.

6.4 Recommendations for Faster Starts

Wood recommends the following

1. Auxiliary Steam must be available to maintain the Auxiliary Steam Header Pressure. Without Auxiliary Steam Fast Starts are not viable. Auxiliary steam will allow for the Main Residual Fuel Oil Storage Tank and Day Tank Temperatures to be maintained at levels that will allow Main Oil firing earlier than what the present-day scenario dictates. Main burner Atomizing and Scavenging Steam pressure permissives required prior to firing any main oil gun would also be available immediately. The additional benefit of maintaining the powerhouse heating will also be satisfied. The primary alternatives for providing auxiliary steam are a dedicated auxiliary boiler (electric or fuel) or using an existing boiler at reduced output.
2. Our recommendation for providing Auxiliary Steam is that Unit 3 boiler, when not being used as a power generating source, be fitted with a limited number of smaller tipped interchangeable mechanically atomized main oil burners. This will allow the boiler to run at much lower operating

pressures and limits the amount of steam drum pressure cycling. These guns would be fitted into the same burner assemblies presently used. More detailed engineering and testing of this modification should be done to determine all necessary requirements. Within the DCS boiler controls, some additional logic will be necessary to allow the controls to work in the new environment. These burners and the boiler control logic can be switched back to the normal if Unit 3 is required as a power generator. Another advantage of using Unit 3 is, as of now, it is the only boiler with economizer recirculation which has benefits with respect to not having the economizer boil dry causing economizer tube failures and heavy fluctuations in drum level. This method does have drawbacks, as it is not an efficient mode of operating a boiler of this size. However, once one of the other unit boilers and turbine-generators are in operation, shutting down Unit 3 until required will reduce fuel consumption.

3. FGT Monitoring Equipment must be installed on all units. During a fast start, the unit boiler would be knowingly operated outside of the OEM limits. Without adequate FGT Monitoring, faster starts are not reliable and there is risk of damaging the superheater and reheater sections of the boiler. Controlling the firing rate and therefore the boiler FGT to maintain temperatures less than 538°C in the superheater / reheater sections of the boiler is critical to preventing overheating of the tube due to insufficient steam flows through them. (Reference "Combustion Fossil Power" 1991 edition Chapter 21 Pages 6-7 and also the General Electric Start-up and Loading Manual)
4. Optical FGT Monitoring is recommended. Retractable FGT probes are original to the unit but have not been used for many years; recommissioning them is not considered viable. Referencing the temperatures of the thermocouples located near to the headers of the superheater and reheater tubes is not satisfactory. These thermocouple locations are shielded from the actual flue gas and therefore do not provide satisfactory information during the starts.
5. Main Fuel Oil Day Tank recirculation and heating are recommended. This modification would maintain the Day Tank Oil temperature closer to that required to fire a main burner and reduce demand on the individual unit oil system heaters to raise the temperatures above 85°C. One of the observations made during the low load testing was the Day Tank temperature was as low as 36°C in the month of June. During the Winter months the Day Tank temperatures may even be lower with the current system. A suggested location for this system would be where the former Auxiliary Boiler Fuel oil pumps and heat exchangers were originally placed.
6. Permanent economizer recirculation should be installed on Units 1 & 2 (already on Unit 3 as part of original design). Keeping the economizer tubes that are exposed to higher FGT filled with water at all times provides the cooling necessary to prevent unnecessary damage. This recommendation was made in 2007 but not acted on at the time. Faster start times will be infringed upon and unit reliability diminished if these are not installed.
7. Lower waterwall header drain valves on all three units should be motorized. Operating limits must be installed in the DCS to prevent these valves from being opened above 3000 kPa as per the OEM's guidelines. Requirement for manual adjustment of these valves creates unnecessary boiler trips during the start process due to high or low drum levels. HTGS staff would be unable to stay in this one area until the request to open or close them is made as other duties are required.
8. Motorize the Steam Drum Continuous Blowdown Valves on Units 1 & 2 making them like Unit 3 and providing controls into the control room is recommended. The present situation requires that an

operator be dispatched to the 9th or 10th floor to manually operate these valves. The control room operator is required to make drum level adjustments quickly above 3000kPa and this system provides the optimum safe way for that to happen.

9. At least one main storage tank should be fitted with a recirculation pump to ensure the existing fuel heating system is effective and the stored volume of fuel remains accessible in Winter.
10. A lay-up procedure should be developed with objective of protecting the asset and facilitating quick response to an emergency request. If required for the procedure, the existing N_2 piping should be verified and repaired as necessary. Also, the addition of guillotine dampers on the flue gas outlet ducting of the rotary Lungstrom Air Heaters should be considered to prevent corrosion of the outer walls of the boiler tubes and ductwork
11. Staffing arrangements (numbers on shift, numbers on call, experience, etc.) for various scenarios should be developed so that costs are minimized but the assets are protected and the station is capable of responding as expected. These arrangements will correspond to the various states of readiness defined by NLH and NLSO.
12. Installation of piping from the individual Units 1 & 2 Auxiliary Steam Header to the turbine gland steam system should be considered. Some utilities have used this modification to heat the HP and Intermediate Pressure (IP) turbines and may be beneficial if faster start times are desired. Unit 3 is already equipped with this capability and the effects on that Unit could be tested before installing the piping on Units 1 & 2. To establish the warming condition, steam at approximately 180°C from the Auxiliary Steam header would be introduced to the HP, IP, and LP turbines through the Turbine Gland Steam system, and using the Condenser Air Extraction Pump to draw a minimal vacuum on the Condenser creating a warming steam flow through the unit from the glands into the main body of the Turbine casings.

6.5 Budget Considerations

Faster starts are desirable now but will be essential if HTGS were to serve as a backup facility. The following budget items should be implemented well before the transition to emergency power readiness so that the systems and procedures can be fully commissioned and HTGS staff gain experience with them.

Operating Budget

The most significant operating expenses will be fuel and labour. The magnitude of these expenses will be determined by the required state of readiness and duration of that state. Various levels of readiness can be envisioned; NLH and the NLSO must determine when such levels are required, if at all.

- A condition of no auxiliary steam production and no synchronous condenser operation may be considered during the Summer months when demand is reduced. At such times there will be no fuel consumption and only a skeleton staff will be necessary. However, fast starts will not be possible from such a condition.
- Producing auxiliary steam from Unit 3 boiler will require fuel consumption and modest amounts of additional staff. This would be desirable during the Winter months to provide fast starts and plant heat.

- Holding a unit online at minimum load when necessary for emergency or unplanned reasons will increase operating costs further but will provide spinning reserve capacity in addition to allowing fast starts of other units.

Other operating costs will be one-time expenses and are considered minor such as boiler tuning, logic programming, preparing procedures, and associated engineering.

Capital Budget

The recommendations considered essential, using Unit 3 boiler for auxiliary steam, installing Optical FGT monitoring and day tank recirculation and heating, will have a capital investment of approximately $400,000. Wood recommends these changes be implemented first or in conjunction with other improvements. The table below lists capital cost estimates (+100% / - 25%) for the recommendations. Except where noted, cost estimate is for all three units.

Recommendation	Priority	Estimated Cost
Use Unit 3 Boiler for Auxiliary Steam	Essential	$100,000
Optical FGT Monitoring	Essential	$100,000
Day Tank recirculation and heating	Essential	$200,000
Main storage tank recirculation	High	$300,000
Refurbish N_2 fill system	High	$50,000
Units 1 & 2 Economizer Recirculation	Moderate	$300,000
Motorize valves: lower waterwall header drains	Moderate	$200,000
Motorize valves: steam drum continuous blowdown	Moderate	$200,000
Units 1 & 2 Turbine gland seal auxiliary steam piping	Moderate	$50,000

7. Viability of Reducing Conversion Time on Unit 3 from Synchronous Condenser to Generator

The time required to complete the changeover from synchronous condenser to generator currently ranges five to seven days. The HTGS Procedure requires that the generator casing be purged of H_2 using CO_2 and then remove the CO_2 using air before the mechanical changeover can begin. The above procedure then needs to be done in reverse before the unit is started as a power generator after the conversion. The purging of gases is done as a safety precaution.

Maintaining this method but accelerating the process will require installing significantly larger diameter piping, enlarging tie-points on the generator, and possibly heating of the gases. A simpler solution is to leave the H_2 in the generator during the conversion, thereby reducing conversion time by four days and maintenance staff could then re-couple the generator to the steam turbine in three 10-hour days.

Wood was unable to locate any utilities that currently convert from synchronous condenser back to steam powered generator. Most utilities that have converted their generators leave them as condensers and dismantle the steam generator portion of the unit. One utility that routinely completed the conversion in the past did it with H_2 left in the generator.

Wood recommends leaving H_2 in the generator during conversion, possibly at a somewhat reduced pressure, and leaving the generator seal oil system in service. The seal oil system is a totally contained separate system that pumps oil to the generator shaft seals at a controlled differential pressure that is higher than the H_2 pressure. This ensures that H_2 does not leak into the atmosphere and therefore does not pose a risk to the work being done to complete the conversion.

Since commissioning this report, NLH engaged Emeric Solutions to review the existing HTGS Unit 3 configuration and existing procedure to convert HTGS Unit 3 from Generator to Synchronous Condenser modes. The final intent is to implement the unit conversion with H_2 in the vessel. If deemed feasible, Emeric Solutions shall prepare a procedure for HTGS to convert Unit 3 between synchronous condenser and generator modes while leaving H_2 in the generator.

Emeric Solutions are presently engaged to oversee the design, construction, commissioning, and maintenance programs for the synchronous condensers at the Soldier Pond Converter Station. They also have significant experience associated with the design, operation, and maintenance for a variety of Canadian utility owned H_2 cooled synchronous condensers.

Upon completion, we recommend this procedure be thoroughly reviewed with HTGS maintenance and safety personnel to ensure they have confidence in the methodology, and the procedure be used for all such conversions and not reserved only for emergency conditions.

7.1 Budget Considerations

The next opportunity to convert Unit 3 from synchronous condenser to generator will be the Fall of 2020. If the new procedure is completed and reviewed, it should be used for the next conversion.

Operating Budget

No additional costs are anticipated other than the one-time costs to develop the procedure. There is the possibility that the overall cost to complete the conversions may be reduced.

Capital Budget

There are no capital budget expenditures anticipated.

8. Conclusions

Wood studied three current operational performance limitations at HTGS and concludes that each of these can be significantly improved with modest investment. It is technically viable to change the mandate of HTGS from reliable baseload winter generation to backup power. The level of improvement possible to minimum load, start times, and synchronous condenser to generation conversion time warrant further consideration of the economic viability of HTGS as a backup facility when no longer required as a baseload resource.

Several recommendations are listed in previous sections. The following recommendations are considered essential.

- Revisions to control logic and boiler tuning are required for both lower minimum loads and faster starts.
- Auxiliary steam is available when HTGS is not generating but available. Without auxiliary steam, fast starts are not viable. Wood recommends using Unit 3 boiler to provide auxiliary steam.
- FGT monitoring equipment is installed to ensure the boilers are not inadvertently damaged during fast starts.

Appendix A

Minimum Load Testing Parameters Monitored

Unit Boiler and Associated Equipment

East and West Forced Draft fans discharge pressures

East and West FD fan bearing vibrations

East and West FD fan variable speed motor amperages

East and West FD fan speeds

Boiler Windbox Pressure

Boiler Air Flows (East and West)

Furnace Pressure

Boiler Opacity

Boiler Excess Oxygen (as a percentage)

Burner Tilt positions on ABCD elev. U1&U2

Main Fuel Oil Pressure Control Valve position (%)

Main Fuel Oil Filter Differential Pressures

Main Fuel Oil Pressure at the Burners

Main Fuel Oil Temperature

Main Fuel Oil Flow

Boiler Drum Level

Boiler Feedwater Pump East or West amperage

Boiler FW Pp East/ West bearing vibrations

Boiler FW Pp East/West discharge pressure

BFW Drum level Control Valve position

Boiler Steam Drum Pressure

Boiler Feedwater Flow

Boiler Main Steam Flow

Boiler Superheater tube Metal Temps

Boiler Reheater tube Metal Temperatures

Main Oil Day Tank Temperatures

Main Steam Turbine Generator and Associated Equipment:

Main Steam Temperatures at Turbine

HP Turbine 1st Stage Metal Temperatures (Inner & Outer)

HP Turbine Throttle Pressure

HP Turbine Control Valve Position in %

Hot Reheat Steam Temperatures

Cold Reheat Steam Temperatures

Reheat Bowl Inner and Outer Temperatures

Turbine Drain positions (open or closed)

Steam Turbine Differential Expansion

Steam Turbine Shaft Eccentricity

LP Turbine Exhaust Hood Temperatures

Turbine Condenser Vacuum Pressures

Generator Casing Hydrogen Pressure

Generator Hydrogen Temperatures

Generator MW Output

Generator MVAR Output

Steam Turbine/Gen. Bearing Shaft Vibrations

Appendix B

Minimum Load Test Procedures

Test Methods

1) Lower Unit Load to 30 MW Operating at Design Pressures on Boiler and Turbine

a) Starting with the present-day minimum load of 70 MW's and the steam turbine throttle pressure at design of 12.9 MPa allow the unit to stabilize and take a full set of readings.

b) Closing the steam turbine control valves lower the unit loads to 60/50/40/30 MW's. Monitoring the selected points during each load reduction allowing the unit to stabilize for 30 minutes at each load. Take a full set of readings for each load value before moving to the next megawatt value.

c) Ensure that the turbine load limiter is set just above the load desired at each test load.

d) Depending on the condition of the unit i.e. turbine metal temperatures, turbine /generator vibrations, differential expansions and eccentricity, fuel oil filter differential pressures, main steam temperatures, burner tilt positions, and how the Boiler Feed Water is operating hold the unit at this load for at least six hours.

e) Release the unit to NLSO to load as required for system operations

2) Partial Sliding Pressure Partial Control Valve Closure to Achieve Minimum Load of 30MW

Reduce the boiler firing rates to lower the HP turbine throttle pressure from the design to a lower predetermined value ultimately causing the unit load to decrease to an unknown value. After reaching the unknown load continue lowering the load down to 30 MW using the unit Control Valves. Reducing the boiler pressure will allow the control valves to stay open longer and limits the throttling across these valves. Throttling causes the main steam to cool the HP Turbine metal temperatures creating excessive stress as the unit load is increased. Another advantage of using this method is by reducing the boiler pressure the risk of a secondary superheater outlet safety valve lifting is diminished. When these valves blow off high pressure steam into the atmosphere, high noise levels are generated

a) Starting with the present-day minimum load of 70 MW and the steam turbine throttle pressure at design of 12.9 MPa allow the unit to stabilize and take a full set of readings.

b) Reduce the boiler firing rate lowering the turbine throttle pressure to 11 MPa and determine what the unit load settles out at. When the load settles record the MW value and take a full set of readings. Allow the unit to stabilize for 2 hours and again take a full set of readings.

c) After determining what the load is, close the Control Valves and reduce the unit load to 30 MW while maintaining 11 MPa turbine throttle pressure. Allow the unit to settle out and take a full set of readings.

d) Depending on the condition of the unit i.e. turbine metal temperatures, turbine /generator vibrations, differential expansions and eccentricity, fuel oil filter differential pressures, main steam temperatures, burner tilt positions, and how the Boiler Feedwater system is operating hold the unit at this load for at least six hours.

e) Release the unit to NLSO (ECC) to load as required.

3) Total Variable Pressure Drop from Design Pressure to 30 MW

Reduce the Boiler Firing while leaving the turbine control valves either in position after reaching 70 MW or opening them to full open (full arc) after the HP turbine throttle pressure has decayed significantly. Continue to reduce the throttle pressure until the unit load reaches 30 MW. Operating in this manner prevents any throttling action across the Control Valves and therefore reduces the chilling effect that closing the control valves have on the turbine metals.

a) Reduce the firing rate allowing the throttle pressure to slide until 30 MW is obtained from todays present minimum load of 70 MW. (Note this test should only be performed after a full discussion with NLSO and what the ramifications might be if another generating unit on the grid was to trip.)

b) Operate the unit for a period of 2 hours at 30 MW while taking readings every 15 minutes.

c) Depending on how the Unit operates extending the test to an additional 6 hours to determine long term operating effect should be considered.

d) Release the unit to NLSO (ECC) for normal operating requirements.

4) Reduce Load using CV's then Transferring Control to Main Stop Bypass Valve

a) With the unit at the present day minimum load of 70 MW reduce the load down to 30 MW using the control valves and transfer the load control to main steam stop valve bypass (designed to supply 20% of the steam flow to the turbine which equates to approximately 30 MW based on the original design of the turbine before the uprating) Open the control valves to the full open position once it has been determined that they are no longer controlling the steam flow.

b) Operate the unit for a 3-hour period in this condition taking readings every 15 minutes.

c) Depending on how the unit is operating extending the test for an additional 6 hours should be considered.

d) Release the unit to NLSO (ECC) for normal operation.

Appendix C

Unit Pre-Conditions for a Cold Fast Start

Common Systems

- Auxiliary Steam Header 0-AS-03-300 must be fully pressurized to 1400 kPa and the 700 kPa 0-AS-03-301 line supplying the Main oil Tank Farm and the Main Oil Day Tank must be in service.
- The Common Water Treatment Plant must be available for supplying treated water to the unit boiler for makeup including the Reserve Feedwater Systems on the unit being started.
- The individual unit chemical dosing tanks and pumps are available in automatic or available with some Operator intervention with the appropriate chemicals to begin dosing as required.
- The units associated General Service Water and Turbine/Generator Auxiliary Service Water Systems along with the Raw Water Supply are in operation or available to operate.
- The associated units fire water system is in service. Note: This system should be available at all times or an appropriate fire watch is provided.
- The associated units Instrument and Service Air Systems are in service for at least the unit requested.
- The plant 4KV & 600VAC and the unit Uninterruptible Power electrical buses along with the 250V & 125V DC buses for the unit being started must be in service.
- The H_2 and CO_2 bulk supply systems must be available to the unit requested.
- Main Fuel Oil Storage Tanks (at least one tank) and its associated Suction Heater is in service and the steam tracing on the Main residual oil piping supplying the Residual Oil Day tank is in service.
- The Light Oil Storage Tanks (at least one) is available supplying the suction header common to all the units light oil pumps.
- All sumps and associated pumps along with the common wastewater treatment facility used with respect to the operation of the plant and specifically the unit being requested are available for service.

Unit Boiler Systems

- Unit Condenser hotwell, Condensate Extraction Pumps (at least one), Condensate Polishers and the remaining LP Feedwater System including the Gland Steam Condenser, LP heaters 1 & 2 with associated heater drips and vents, the Deaerator and Deaerator Storage Tank are available for service. All nitrogen connections on the LP Feedwater System including the Deaerator must be disconnected and heater venting re-established before starting the unit. Note that there is a safety concern when using Nitrogen to layup the equipment. Nitrogen does not support life and therefore monitoring should be installed and periodic atmospheric testing should be completed on the ground floor of the powerhouse to ensure nitrogen has not escaped from any of the above associated equipment.
- Unit HP Boiler Feedwater system is available for service including Boiler Feed Pumps (at least one) and the HP heaters 4, 5, and 6 are available for service. Included in this would be the HP heater drip system and HP heater vents. If an HP feedwater heater is unavailable due to any reason then depending on which heater and what the turbine OEM's limits are, a maximum unit load restriction may apply. The boiler economizer inlet manual valve must also be open. Nitrogen should be used to protect the heater shells from corrosion and oxidation if long term shutdowns are expected. Disconnection of the nitrogen would be necessary before starting the unit and heater venting re-established.
- Boiler waterwall circuits and the Steam Drum must be full of treated demineralized water and the Steam Drum maintained at the highest level possible without putting water into the primary superheater. If filling the superheaters and the main steam piping with demineralized water becomes part of the layup procedure, then all necessary hangar rod pins must be installed in the main steam lines from the boiler down to the turbine in order for

those lines to withstand the weight that the water would create. Unless the shutdown periods are excessively long this portion of the layup procedure should be thought through carefully before being carried out as all the steam piping would require draining and all hangar pins must be removed before starting the units boiler. All waterwall manual drains and vents must be closed to ensure no leakage or air ingress before the nitrogen blanketing is applied. All superheater manual drains and atmospheric vents must be closed along with the main steam boiler stop valve if available. (if BSV is not available then Turbine Main Stop Valves must be kept closed and any drain valves associated with these must be manually closed as nitrogen will migrate into these systems. This only applies if nitrogen blanketing is applied to the boiler through the connection at the Steam Drum and the Cold Reheat Piping. Disconnection of the nitrogen would be necessary before starting the unit and the manual vents to atmosphere must be opened prior to start.

- Boiler Combustion Air and Flue Gas Circuits including the boiler makeup air system, at least one FD fan, (as long as the discharge damper on the second fan is totally blocked to prevent a backflow of air and flue gas from entering the powerhouse) the combustion air heaters and the rotary Air Preheaters are in service or are ready for service, Auxiliary Air, Fuel Air Dampers, and Burner Tilts on Units 1 & 2 are available and in Automatic. The Boiler Temperature Probe or Optical Temperature measuring is available. If unit 3 is to be started as a power generator then the secondary air registers only are required to be in automatic (Unit 3 does not have burner tilts or Aux air and Fuel Air dampers as it is a different manufacturer). The flame scanner blower, the seal air fans, and aspirating air are available along with the Ignitor Booster Fans for units 1&2. All boiler and ductwork access doors along with flame viewing ports etc. should be closed and ready for boiler operation. As there is no isolation point between the boiler flue gas outlet and the Stack associated to the Unit, and due to the high salt content in the Newfoundland outdoor air, some form of protection should be considered for the outside of the boiler tubes and the inside of the boiler ductwork especially if extreme long- term shutdowns occur. A negative stack draft will occur while not in operation and a small air flow through the boiler to the atmosphere will take place. This airflow will cause some oxidation on the outside of all the boiler tubes and on the insides of the boiler ductwork. In order to prevent this draft from occurring ensure all dampers are closed and are tight shut off or one suggestion although not strongly recommended is placing tarpaulin's over the flue gas sides of the Lungstrom Air Preheaters to stop the flow of air created by the Stack draft effect. The other method to stop the flow of air is the addition of guillotine dampers in the ductwork at the FD fan discharges and on the flue gas outlets of the Lungstrom Air Preheaters. Neither of these recommendations are required immediately but might be considered after determining the critical role Holyrood has within the Newfoundland Power Grid. (Using tarpaulins and removing them would add a great deal of time and effort in starting up a unit)
- Boiler Fuel Systems including the Unit Main Residual Fuel Oil System including strainers, fuel oil heaters, and pumps up to the burner nozzles, the Unit Residual Fuel Oil Additive System, along with all of the piping and valving associated with these systems should be available. The Unit Light oil Ignition Fuel System up to the individual ignitor control boxes and ignitors while including the Common Light Oil Storage Tank and associated piping and pumps. Also required for the main burners is the Atomizing Steam and Scavenging Steam systems fed from the Auxiliary Steam system.
- The boilers DCS must be available

Turbine and Generator Systems

- Turbine Auxiliary Oil System including the associated lubricating oil tank filled to its normal working level with the oil tank vapour extractor in service along with at least one of the two AC oil pumps in service. The associated DC lube oil pump must be available and tested to ensure its operational ability in case there is a total loss of AC power to the unit. The lubricating oil filters must be in service to protect the integrity of the oil before being introduced to the turbine and generator bearings. Unit 3 requires the Turning Gear oil pump to be in service along with the Jacking oil pump to lift the turbine shaft before placing it on Turning Gear. (Units 1&2 do not have this requirement.)

- Turbine/Generator must be available to be put on Turning Gear for a period of at least 8 hours (or a determined reasonable time) if it is not already on turning gear. If the start required is not of an emergency nature then the turbine turning gear immediately should be placed in service to avoid any delays.
- The Turbine Hydraulic Oil system for the unit must be available for service on units 1&2 only. The Main Steam Stop valves, control valves, Reheat Stop Valves and Intercept Valves require this system as well additionally a number of other unit safety devices. Unit 3 requires that the Auxiliary Oil Pump be in service to operate the above listed valves. All of the above valves require to be tested prior to rolling the unit on steam to ensure they function correctly as they all perform a safety function if a premature trip occurs during unit operation.
- Turbine Extraction Steam Non-Return Valves should be tested to ensure they operate correctly. While in service if the unit trips prematurely during normal operation these valves close to prevent an uncontrolled overspeed situation on the unit turbine providing additional safety to the equipment and the staff within the plant.
- Turbine Gland Steam system along with the gland steam exhauster must be available.
- All of the necessary Turbine instrumentation such as vibration monitoring, differential expansion monitoring, eccentricity monitoring, and all other temperature monitoring must be available.
- The unit turbine Mark V control system is available for service.
- The Turbine's Steam Condenser Air Removal System is available.
- All of the Turbine and associated piping drains and blowdown tanks must be open and available for service.
- The Turbines Steam Condenser Circulating Water System is available for service.
- The Unit Generators associated Seal Oil System along with all associated equipment must be in service.
- The Unit Generator casing must be in a pure H_2 environment and pressurized with H_2 to the normal working pressure between 180-210 kPa.
- The Generator Hydrogen Cooling System is in service along with the associated cooling water temperature control valves availability.
- The Generator Field Excitation Transformer and all associated breakers are available for service.
- Generator Exciter Brushes are installed.
- All of the generator potential transformer and current transformer fusing is installed and the generator neutral ground switch is the proper position for unit operation.
- The Generator Main Output Transformer and the Unit Service transformer and their associated Cooling Systems are either in service or available for service.
- The Unit Generator Synchronizing Breaker and Disconnect Switches are available for operation.

wood.

Appendix D

Generalized Procedure for a Cold Start

Once it has been determined that all of the unit pre-conditions have either been satisfied or can be satisfied before being required and the unit has been checked over and ready for operation proceed with the following steps. Some of these steps may be done in conjunction with other activities.

1. If Nitrogen Blanketing has been used to Layup the equipment, disconnect the nitrogen connections and establish all vents and drains associated to that equipment. In parallel, open the boiler drum vents and use the lower waterwall header drains and begin draining the steam drum to a level just above the "low drum level trip setting. (Do this in the expectation of the drum level swell when heat is introduced into the boiler) Ensure the turbine / generator is on turning gear following the pre-established procedures if it has not yet been done. Start the rotary air heater drives. Make sure that auxiliary steam is available to the combustion air coils, fuel oil heaters, burner atomizing steam and scavenging steam systems. Start a Main Fuel Oil Pump and recirculate fuel oil back to the Main Oil Day Tank through the short recirculating valving supplied in an effort to raise the overall fuel oil temperature closer to the limit required for firing the boiler on Residual Oil.
2. Ensure that either the Boiler FGT Probe or the Optical FGT measuring equipment is available before lighting off any fuel source.
3. Start the boiler Forced Draft Fans and establish the boiler purge air flow for the time delay used at HTGS and controlled within the DCS.
4. Ensure that all the start permissives required within the DCS have been met.
5. Once these permissives have been satisfied and the Boiler Trip relay reset use the light oil ignitors to start warming the boiler setting. Establishing at least one full elevation of light oil ignitors to initially warm the boiler setting. (Using the bottom elevation of ignitors is preferable but not absolutely necessary for prewarming the whole boiler setting)
6. Fire the boiler in this manner until it is observed that the boiler drum level is beginning to swell. Using the lower waterwall header drains inch these slowly open to help maintain the level closer to the low drum level trip point.
7. Fire additional ignitors to continue raising the temperature in the boiler waterwall circuits and adjust the total air flow lower without causing a "low air flow boiler trip". (Doing this creates a better heat transfer into the boiler waterwall tubes.)
8. Open the Fuel Oil Trip Valve and ensuring the Long Recirculation Valve is open. Circulating the Main Fuel Oil through the entire units Fuel Oil System will aid in achieving the temperature limits required for burning Residual Fuel Oil.
9. Monitor all temperature points within the boiler to ensure none are being exceeded as prescribed by the OEM. This includes the inner and outer drum metal differential temperatures, any primary and secondary superheater limits and the FGT which must be kept below 538°C during the entire startup process.
10. Start the Condensate and Boiler Feedwater systems as necessary to provide feedwater to the boiler when required.
11. When the boiler drum pressure reaches 35 kPa or the value as defined by HTGS procedures close the steam drum vents and begin firing a Main oil gun preferably on "A" elevation and monitor the FGT probe to ensure that the FGT stay below 538°C . When the drum level is relatively stable and the FGT is under control aggressively increase the firing rate so as to not exceed these limits and raise the pressure and temperature of the steam throughout the entire unit down to the Main Steam Stop Valves using the boiler drains as necessary.
12. Start a Condenser Cooling Water Pump and establish the necessary systems i.e. Travelling Screens etc. etc.
13. Establish the Turbine Gland Steam system when the boiler pressure reaches approximately 1600 kPa.
14. Begin HP Turbine prewarm by following the GE recommended procedure and using HTGS operating guidelines.
15. When the HP Turbine 1st Stage Inner metal Temperature reaches 100°C close the main steam stop valve bypass while continuing to raise boiler pressure and temperature.

16. Continue drawing condenser vacuum down to normal operating values and proceed to roll the main turbine /generator on steam to 500 RPM. (full vacuum is not totally necessary before rolling the unit on steam however the values required will be HTGS specific)
17. Hold 500 RPM and physically check the turbine / generator to ensure it is operating normally. (GE recommends that the unit not be operated at speeds lower than this for long periods)
18. Continue raising the speed up towards Synchronous Speed moving quickly through the Critical Speed values up to 3000 RPM. Hold 3000 RPM and check the IP turbine to LP Turbine Crossover Temperatures and as well the IP Turbine Reheat Bowl Inner Metal Temperature to ensure the values are above 100°C before proceeding to the 3600 RPM Synchronous Speed. (GE recommended)
19. Apply the Generator Field and Synchronize the Unit in conjunction with the approval from the ECC.
20. Slowly raise the generator load and transfer the station service load to the Unit Service Transformer at the load specified by HTGS Procedures.
21. Raise the unit load to the minimum value of 30 MW's using the Main Seam Stop Valve Bypass and as conditions permit load the generator as per the ECC requests.