Engineering Support Services for

the Lower Churchill Project

Newfoundland and Labrador Hydro

PM0011 – CCGT Capital Cost Benchmark Study
Final Report

December 19, 2008

Newfoundland and Labrador Hydro
Lower Churchill Project

PM0011 - CCGT Capital Cost Benchmark Study

Final Report - December 2008

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Executive Summary

Newfoundland and Labrador Hydro (Hydro) retained Hatch to carry out a Capital Cost Benchmarking Study for a Combined Cycle Gas Turbine (CCGT) facility. The study included three site locations across Canada and three different plant capacities:

Locations: [redacted]

Option 1: One 125 MW combined cycle power plant block. The block includes two (2) GTG gas turbine generators, two (2) HRSGs, and one (1) steam turbine generator.

Option 2: One 275 MW combined cycle power plant block. The block includes one (1) GTG gas turbine generators, one (1) HRSGs, and one (1) steam turbine generator.

Option 3: One 500 MW combined cycle power plant block. The block includes two (2) GTG gas turbine generators, two (2) HRSGs, and one (1) steam turbine generator.

In addressing the scope of this assignment, it was recognized that specific site selection work has not yet been conducted. Therefore, the basic assumptions made included an assumption that the future site selection work would focus on location of a site that had the key attributes listed below. It is noted that variations in any of these assumptions will have some impact on a specific project cost.

1. Proximity to an existing major gas transmission pipeline or compressor station. [redacted].
2. Proximity to electrical transmission capacity to match the delivery capacity of each of the power plant configurations studied.
3. Regulatory permits that would enable the use of gas turbines with DLN combustors without the need for incremental emissions reduction facilities.
4. Land designated for industrial development of suitable construction characteristics such as construction access, ease of major equipment delivery accessibility, suitable area for site runoff and waste water management and adequate geotechnical characteristics to avoid the use of piling.
5. Proximity to an adequate water supply.

The study is intended to have a general understanding of the influence on performance and costs based on the main characteristics of the three different locations. All the estimates are given in 2008 US dollars. Table E.1 is a summary of the findings for the three different locations and capacities.

Table E.1
Summary of Three Different Options per Location

Study Option:	Option 1 (Nominal 125 MW)			Option 2 (Nomial 275 MW)			Option 3 (Nominal 550 MW)		
Location:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Project Cost (MUSD)	183	185	181	329	334	325	625	633	617
Cost /kW	1,467	1,485	1,448	1,199	1,215	1,183	1,137	1,152	1,122

The estimates were developed for each of the three configurations and three sites. For the power plant areas, budget quotations were received for the LM6000 as well as the 7FA model gas turbines, HRSGs and steam tubines. For the rest of the plant, estimates were based on 2008 in-house data. Given the current currency fluctuations, the estimate is developed in US dollars.

In order to predict power plant costs given the desired output power, a model to relate the unit cost of a new power plant varying with installed capacity was developed. The estimates developed for the three configuration as well as estimates developed exclusively from in-house data was used to develop the regression anlysis model. The resulting data points were plotted from the total unit costs to build a CCGT plant over sizes ranging from approximately 50 MW to 600 MW. The total unit costs are a function of equipment costs, labour costs, balance-of-plant costs, indirect costs, engineering costs and contingencies. These unit costs were estimated in accordance with the power plant cost estimate basis.

The results of this regression analysis show a trend of decreasing unit costs with increase in plant size. The slope of this curve decreases with increase in plant size. This behaviour can be explained by two major factors which are economies of scale as well as increasing plant complexity with size increase. The economies of scale factor results in reduced costs with increase in plant size whereas the plant complexity factor results in increasing plant costs with increase in plant size due to design, construction and planning complexities of a large plant.

1. Introduction

Hatch was retained by Newfoundland and Labrador Hydro (Hydro) to carry out a Capital Cost Benchmarking Study for a Combined Cycle Gas Turbine (CCGT) facility using natural gas as fuel. The study was to consider three plant capacities, nominally 125, 200 and 500 MW, for which preliminary capital costs would be developed. The cost data would be a combination of Hatch in-house data from recent projects, external published data, and, where possible within the time frame of the study, vendor data for major equipment. The preliminary costs of these plants were then to be used in the development of a regression analysis model which would demonstrate a relationship between unit capital cost and plant capacity.

2. Plant Location Parameters

As stipulated in the WTO, sites in [redacted] were considered. These sites are close to existing fuel pipelines and interconnection infrastructure. For plant performance and configuration purposes, the temperature characteristics shown in Table 2.1 were used. The potential effects of the different sites on costs are briefly addressed in section 5.3.

Table 2.1
Site Conditions

Site	Elevation, m	Ambient Temperature, °C	Dry Bulb °C
[redacted]	40	20.7	23.6
[redacted]	71	20.6	24.7
[redacted]	173	22.2	26.9
Average	94.7	21.2	25.1

The plants will be connected to the existing grid in the area. Therefore, there is no need for black-start capability. The power plant will operate with natural gas as a single fuel for the duration of the plant life. It is assumed that natural gas will be supplied from an existing gas pipeline in close proximity to the proposed site by the gas company. The gas will be supplied at the corresponding pressure required to meet the gas turbine minimum requirements without the need for on-site compression and treatment other than filtration and heating. This could be somewhere along the [redacted] to enable a gas supply pressure required for each of the gas turbine selections.

The natural gas is assumed to have a typical composition as shown in Table 2.2. This is the range of natural gas quality typically experienced in the eastern pipeline system referenced to supply [redacted]

Table 2.2
Pipeline quality Natural Gas Typical Composition (range)

Description	
Gross Heating Value (kJ/m3)	36,000-40,200
Calorific Value kWh/m3	10-11.16
Analysis	**% by Volume**
Methane	87-96
Ethane	1.8-5.1
Propane	0.1-1.5
Butane	0.01-0.3
Nitrogen	1.3-5.6
CO_2	0.1-1
H_2S	0

3. Power Plant Performance

Three plant configurations were evaluated to suit the design basis and criteria requirements; these configurations, which differ somewhat from the nominal capacities in the WTO, are as follows:

- One 125 MW combined cycle power plant block. The block includes two LM6000 GE gas turbine generators (GTG), two Heat Recovery Steam Generators (HRSG), and one steam turbine generator (STG).
- One 275 MW combined cycle power plant block. The block includes one 7FA GE GTG, one HRSG, and one STG.
- One 550 MW combined cycle power plant block. The block includes two 7FA GE GTGs, two HRSGs, and one STG.

One case using average site conditions with no duct firing has been examined for each of the above options. In addition, extreme conditions are presented to evaluate the performance of the cycle during summer and winter conditions without duct firing.

This report does not attempt to identify the optimum configuration. Further studies are required in order to identify the best option taking into consideration, capital cost, operating cost, and compliance with environmental regulations.

Using the average data for the site conditions presented in Table 2.1, the performance of each of the three configurations was calculated, and the results are shown in Table 3.1. The performance data of these options, at similar site conditions, are presented below. The results compare the power output, fuel consumption and plant efficiency among other parameters. The final output will be affected by the actual conditions of the site selected. Table 3.2 shows the performance results for summer and winter operation.

Schematics of the plant cycles are attached as Appendix A.

Table 3.1
Plant Performance- Average Conditions

	Configuration Options Average Conditions Comparison				
	Description	**Unit**	**Average**		
			1	**2**	**3**
1	Ambient Temperature	C	25.1	25.1	25.1
2	Relative Humidity	%	71.06	71.06	71.06
3	CTG Gross Electric Output **per Unit** (base load 2 Units)	MW	42.6	159	159
4	STG Gross Electric Output	MW	26.6	84	168.3
5	Gross Plant Electric Output (base load)	MW	111.8	243	486.4
6	Net Plant Electric Output (base load)	MW	108.6	236.9	473.9
7	Plant Efficiency (HHV)	%	51.55	53.55	53.56
8	HP Steam Generation	tonnes/hr	81.28	201	400.7
9	HP Steam Temperature	C	441	441	441
10	HP Steam Pressure	Barg	69	110	110
11	Re-heat Steam	tonnes/hr		244.1	484.5
12	Re-heat Steam Temperature	C		454.4	454.4
13	Re-heat Steam Pressure	Barg		10.3	10.3
14	LP Steam Generation	tonnes/hr	31.1	8.84	17.78
15	LP Steam Temperature	C	182.7	180.8	180.8
16	LP Steam Pressure	Barg	8.6	1.026	1.026
17	CTG Burner Gas Consumption (per unit at maximum process capacity)	tonnes/hr	8.175	34.42	34.42
18	Duct Burner Gas Consumption	tonnes/hr			
19	Total Gas Consumption	tonnes/hr	8.175	34.42	68.84

Table 3.2
Summer and Winter Performance

Configuration Options Summer and Winter Comparison								
	Description	**Unit**	**Average-Summer**			**Average-Winter**		
			1	**2**	**3**	**1**	**2**	**3**
1	Ambient Temperature	C	31.5	31.5	31.5	-15	-15	-15
2	Relative Humidity	%	60	60	60	60	60	60
3	CTG Gross Electric Output **per Unit**	MW	39.8	151.4	151.4	50.15	201.4	201.4
4	STG Gross Electric Output	MW	25.8	82.3	164.9	27.2	87.7	175.9
5	Gross Plant Electric Output (base load)	MW	105.4	233.7	467.8	127.6	289.2	578.9
6	Net Plant Electric Output (base load)	MW	103.2	228.1	456.4	125.3	283.3	567.1
7	Plant Efficiency (HHV)	%	51.53	53.33	53.36	52.75	52.5	52.54
8	HP Steam Generation	tonnes/hr	80.59	198.8	396.1	81.4	212.5	423.4
9	HP Steam Temperature	C	441	441	441	425.9	423.9	423.9
10	HP Steam Pressure	Barg	68.42	108.8	108.8	68.2	113.7	113.6
11	Re-heat Steam	tonnes/hr		241.1	478.5		268.9	533.9
12	Re-heat Steam Temperature	C		454.4	454.4		184.5	426.2
13	Re-heat Steam Pressure	Barg		10.17	10.17		11.1	11.1
14	LP Steam Generation	tonnes/hr	29.55	8.53	17.15	35.23	10.71	21.66
15	LP Steam Temperature	C	181.8	180.3	180.2	183.90	184.50	184.30
16	LP Steam Pressure	Barg	8.4	1.013	1.013	8.84	1.10	1.11
17	Total Gas Consumption	tonnes/hr	15.55	33.27	66.54	18.48	41.98	83.96

4. Power Plant Description

In general, the three plant configurations will differ only in the type and output of the major equipment. The main equipment characteristics are presented below.

4.1 Gas Turbine Selection

Each GTG package will consist of a single-shaft gas turbine coupled to a generator, with mechanical and electrical support systems for unit operation and control. The units will be supplied as complete packaged assemblies utilizing manufacturers standard supply equipment. This procurement philosophy optimizes equipment modularization from the factory. The GTGs will be equipped with the following required accessories to provide safe and reliable operation:

- Compressor, gas turbine, inlet air filters with silencers, evaporative coolers, motor driven starting package.
- Fuel gas main filters/separators.
- Redundant lube oil cooler.
- Dry Low NOx (DLN) combustion system.
- Compressor water wash system.
- Turbine and generator acoustical enclosure.
- Electrical/controls, excitation system and transformer.
- Fire detection and protection system.

4.2 Heat Recovery Boiler and Exhaust System

The HRSGs will be supplied to operate directly with the combustion turbines to generate the steam required for steam turbine operation. The HRSGs are two or three pressure design (HP, IP and LP), natural circulation, water tube type designed for gas turbine exhaust. Each HRSG shall be complete with inlet ductwork from combustion turbine exhaust connection, including expansion joint, HRSG exhaust duct, and exhaust stack. Duct firing capabilities could be added if economically justifiable.

Each HRSG would include the following:

- Three pressure non reheat HRSG for Option 1.
- Three pressure reheats for Option 2 and 3.
- Includes HP, IP & LP drums, complete with drum safety relief valve with silencers, level gages, remote level indication, control unit, and associated vents and drains.
- Superheaters, reheater, evaporator and economizer sections.
- Superheater attemperators, reheater attemperators.

- Inlet ductwork from combustion turbine exhaust, with expansion joint.
- HRSG exhaust duct with expansion joint.
- If applicable, duct burner system including a gas control module with all the required reducing valves, vents and instrumentation, burner management, scanners, dual scanner blower assembly, and duct burner controls.
- Single exhaust Stack with test ports and CEM monitor ports, emission ports platforms.
- Motor actuated stack damper.
- Internally insulated HRSG casing with complete liner.
- Manufacturer's standard stairs and access platforms as required to access inspection ports, valve operation and instrumentation and normal boiler operation.

4.3 Steam Turbine Generator

The steam turbines will be of the condensing type installed in a building. The steam turbine will be directly coupled to 60Hz generator and will be of proven design and suitable for continuous operation at all points in the specified operating regime. The STG control system will include all equipment and software necessary to monitor and record thermal stress levels in the turbine rotor.

The steam turbine system consists of a condensing STG (with or without reheat depending on the option selected), gland steam system, lubricating oil system, hydraulic control system, and steam admission/induction valving.

Steam from the HP, IP and LP sections of the HRSG enters the associated steam turbine sections through the inlet steam system. The steam expands through multiple stages of the turbine, driving the generator. On exiting the LP turbine, the steam is directed into the condenser.

4.4 Steam Turbine Bypass System

The HP/IP bypass stations will fulfil the requirements for the steam turbine bypass including:

- Facilitating steam and metal temperature matching during turbine start-up.
- Full load rejection and operation at house load.

4.5 Cooling System

The heat rejection system will receive exhaust steam from the low-pressure section of the steam turbine and condense it for reuse. A dedicated cooling tower will serve the condenser.

Required make-up water pumps will be provided to supply the water lost in the cooling tower. The pumps will transfer make-up water required from the filtered water tank to the cooling system selected.

4.6 Cooling Tower

The prime function of the Cooling Tower is to provide cooling water to the condenser to condense the steam exhausted from the steam turbines. The heat collected in the condensers will be rejected to the atmosphere by means of cooling towers. The water cooled by the CT collects in the basin of the tower, from where it will be pumped back to the condensers and the Auxiliary Cooling Water system.

4.7 Closed Loop Cooling System

A closed-loop auxiliary cooling system will be provided for cooling plant equipment other than the steam condenser and vacuum pumps. Equipment served by the auxiliary cooling water system includes the CTG and STG lube oil coolers, CTG and STG generator coolers, STG hydraulic control system cooler (if required by STG manufacturer), boiler feed pump lube oil and seal water coolers, fuel gas compressor coolers, and sample coolers.

Closed-loop cooling water pumps will pump condensate quality water from the plate heat exchangers through the individual equipment coolers to remove heat. Auxiliary cooling water pumps will pump water from the main cooling water supply through the heat exchangers to the main cooling water return to remove heat from the closed cooling water system.

4.8 Condensate and Feedwater Systems

Two (2 x 100% duty) condensate pumps will take suction from the condenser hot well and supply condensate to the LP economizer and LP drum of each HRSG. A control valve will be provided to regulate the condensate flow based on LP drum level using a three-element control system.

The feedwater system will deliver feedwater from the LP drum to the corresponding HRSG HP and IP drums through their respective economizers over the full range of plant operation. The feedwater pumps will also supply spray water to plant desuperheaters and attemperators. Two identical boiler feedwater pumps shall be provided for each HRSG. Each pump will be designed to provide 100% of the HRSG feedwater demand and other system demands at Base Load operation. The pumps will be equipped with an inter-stage bleed port to provide IP feedwater to the IP boiler via the IP economizers. Control valves will be provided to regulate the feedwater flow to both IP and HP steam drums of each HRSG.

4.9 Noise Emissions

Near field noise limitation will be per OSHA requirements and will apply within all working areas of the plant. In general, all equipment will be specified not to exceed the eight-hour exposure of 85 dbA within 1 m of the source. This will apply at 1.5 m above the operating floor and all platforms included with the equipment. For ducts and enclosures, the noise limit will apply for a height of 3 and 5 m above the operating floor, when measured 1 m from the vertical surfaces of the equipment.

4.10 Continuous Emissions Monitoring

The flue gas in the stacks will be monitored continuously with a Continuous Emission Monitoring System (CEMS). The CEMS will comply with applicable standards. Electronic, stand-alone CEMS reporting will be provided and will comply with applicable regulations.

Environmental monitoring stations external to the plant, if required, should be provided by the client.

5. Power Plant Capital Cost Estimates

5.1 Costing Assumptions

The main assumptions used in the study are as follows:

- Evaporative cooling towers.
- Municipal water will be used for make-up water source for steam cycle and Cooling Towers.
- Wastewater will be returned to municipal sewer system with only primary pre-treatment to meet discharge requirements.
- Standard plant noise abatement methods for near field and far field noise limitations.
- CTG's and STG's to be installed inside a building, HRSG's located outdoors.
- Facility to be natural gas fired only with no back-up fuels.
- Dump stacks for simple cycle operation not included.
- No black start capability.
- Switchyard included for connection at 230 kV (assume to independent feeds to interconnections).
- 230 kV transmission lines not included.
- Natural gas assumed to be available at a pressure and quality meeting gas turbine minimum requirements without the need for on-site compression and treatment other than filtration and heating. Natural gas supply pipeline to facility fence line and metering station not included.
- NOx emissions limits assumed to range from 9 ppm to 25 ppm at HRSG exhaust stack depending on the plant size and GT selection.
- Duct firing is not included and STG and heat rejection system is sized for 2.5 in HgA at summer design conditions.
- Site conditions to be based on average design conditions that will be derived from an average of the following locations: [redacted] The site elevation will also be based on an average of these three locations.
- It is assumed that the site is level with good access and is suitable for use with minimal re-grading ready for fencing and surface clearing. It is generally recommended that when more specific sites have been identified and characterised, that the cost estimates be updated to take into consideration each site specific issues including property acquisition costs, access upgrades, re-grading etc.
- "Brownfield" in terms of this work means an urban area, not reclaimed industrial land.
- Plants to include 100% steam turbine HP/LP bypass systems.

5.2 Estimate Exclusions

The following Owner's costs are not included in the capital cost estimate:

- Client facility in EPCM contractor's office.
- Site land/real estate costs.
- Site seismic assessment.
- Additional costs due to design of power plant for seismic activity or adverse weather conditions.
- Gas pipeline cost from source to site.
- 230kV transmission line costs from HV switch yard to grid connection node.
- Fuel costs during construction.
- Standby generators for black start of the power plant.
- Mobile equipment.
- Test laboratories and office furniture.
- Freight charges to site.
- Currency hedging.
- Additional project insurances depending on site specific risks.
- All taxes, duties, levies, fees and royalties.
- Specific HSE requirements.
- Development beyond project scope.
- Cost of ongoing studies.
- Schedule acceleration cost.
- Process license cost.
- Transmission line costs from site perimeter to closest grid connection node.
- Local community support costs including one time and ongoing costs.
- Sustaining capital.
- Replacement capital.
- Royalties on imported & local materials including local rock for crushing.
- Development fees and approval costs of Statutory Authorities.
- Local community support costs.
- Wet commissioning and ongoing project operating costs.

- Environmental monitoring.
- Escalation beyond the base date of the estimate.
- Variations to foreign currency exchange rates.
- Project closure plan and site cleanup and rehabilitation.
- Schedule delays and associated costs, such as those caused by:
  - Unexpected site conditions
  - Unidentified ground conditions
  - Labour disputes
  - Force majeure, and
  - Unforeseen Permit applications.
  - Escalation beyond the base date of the estimate, 2008.

5.3 Basis of Estimates

The basis of the estimates and procedures applied meet the requirements of the Hatch Project Life Cycle Classification and industry standards for an Order-Of-Magnitude estimate. The purpose of the estimates is to provide indicative capital costs for the proposed power stations given three possible power plant configurations and capacities. Such estimates are done in advance of the more detailed capital cost estimates which are usually undertaken as engineering progresses.

Under the AACE (American Society of Cost Engineers) classification, the estimates are considered to be Class V.

The power plant includes the following areas:

1. Power Island (gas turbines, steam turbines, HRSGs)
2. Power plant auxiliaries (civil, structural, electrical, I&C etc)
3. Generators and HV switch yards on power plant site
4. Water treatment and reticulation systems within site perimeter
5. Site infrastructure(roads, power plant based fuel handling systems, perimeter fencing etc)

For the power plant areas, budget quotations were received for the LM6000 as well as the 7FA model gas turbines and HRSGs. Quotations for gas turbines with HRSGs and steam turbines were obtained for the S207 configuration. For the rest of the plant, estimates were based on 2008 in-house data.

The estimates were developed for each of the three sites, and take into account labour costs differences among the three sites. The regression analysis is developed using average labour costs. Given the current currency fluctuations, the estimate is developed in US dollars.

It is noted that site work and improvements will vary due to the different topography and soil conditions for each of the three sites. This also goes for the buildings, structures and foundations cost contributions due to the additional design requirements for site specific conditions.

5.4 Capital Cost Estimate Description

The capital cost estimate major categories are described below. A breakdown of the estimates for the three configurations and sites is provided in Appendix B and a more detailed breakdown is presented in Appendix D.

5.4.1 Direct Costs

Direct costs are the costs of all equipment and materials, together with construction and installation costs for all CCGT facilities. The direct costs include the costs associated with the following:

- Procurement and installation of new equipment.
- Procurement, fabrication and installation of bulk materials.
- Site preparations (bulk earthworks).
- Procurement, fabrication, erection of buildings and associated services.

5.4.2 Indirect Costs

Indirect costs include the following:

- Temporary construction facilities including worker lodgings/services, secure lay-down areas, warehouses, etc.
- Temporary construction services.
- Construction equipment.
- Freight.
- Vendor representatives.
- Capital spares.
- Commissioning Spares.
- First Fills.
- Engineering, procurement and construction management services (including travel expenses).
- Third party engineering.

- Pre-operational testing services including associated materials.
- EPCM cost.

5.4.3 Contingency

No contingency has been included, as stipulated in the WTO.

5.5 Estimate Summary

Order of Magnitude Cost Estimate Summary

Project:	Lower Churchill Project								
Description:	CCGT Capital Cost Benchmarking Study								
Currency:	USD (2008)								
Study Option:	**Option 1 (Nominal 125 MW)**			**Option 2 (Nominal 275 MW)**			**Option 3 (Nominal 550 MW)**		
Location:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Labour hours	591,070	615,819	566,321	1,080,423	1,127,513	1,033,333	2,146,243	2,235,027	2,057,459
Total Direct Cost	156,357,552	158,350,640	154,364,464	283,317,096	287,109,378	279,524,814	539,471,854	546,621,849	532,321,860
Total Project Cost	183,359,077	185,658,268	181,059,887	329,817,323	334,192,031	325,442,614	625,312,841	633,560,945	617,064,736
Cost /kW	1,467	1,485	1,448	1,199	1,215	1,183	1,137	1,152	1,122

6. Regression Analysis

In order to predict power plant costs given the desired output power, a model to relate the unit cost of a new power plant varying with installed capacity was developed. The resulting data points were plotted from the total unit costs to build a CCGT plant over sizes ranging from approximately 50 MW to 600 MW. The total unit costs are a function of equipment costs, labour costs, balance-of-plant costs, indirect costs, engineering costs and contingencies. These unit costs were estimated in accordance with the power plant cost estimate basis.

Figure 6.1 shows the results of the regression analysis for the benchmarking exercise.

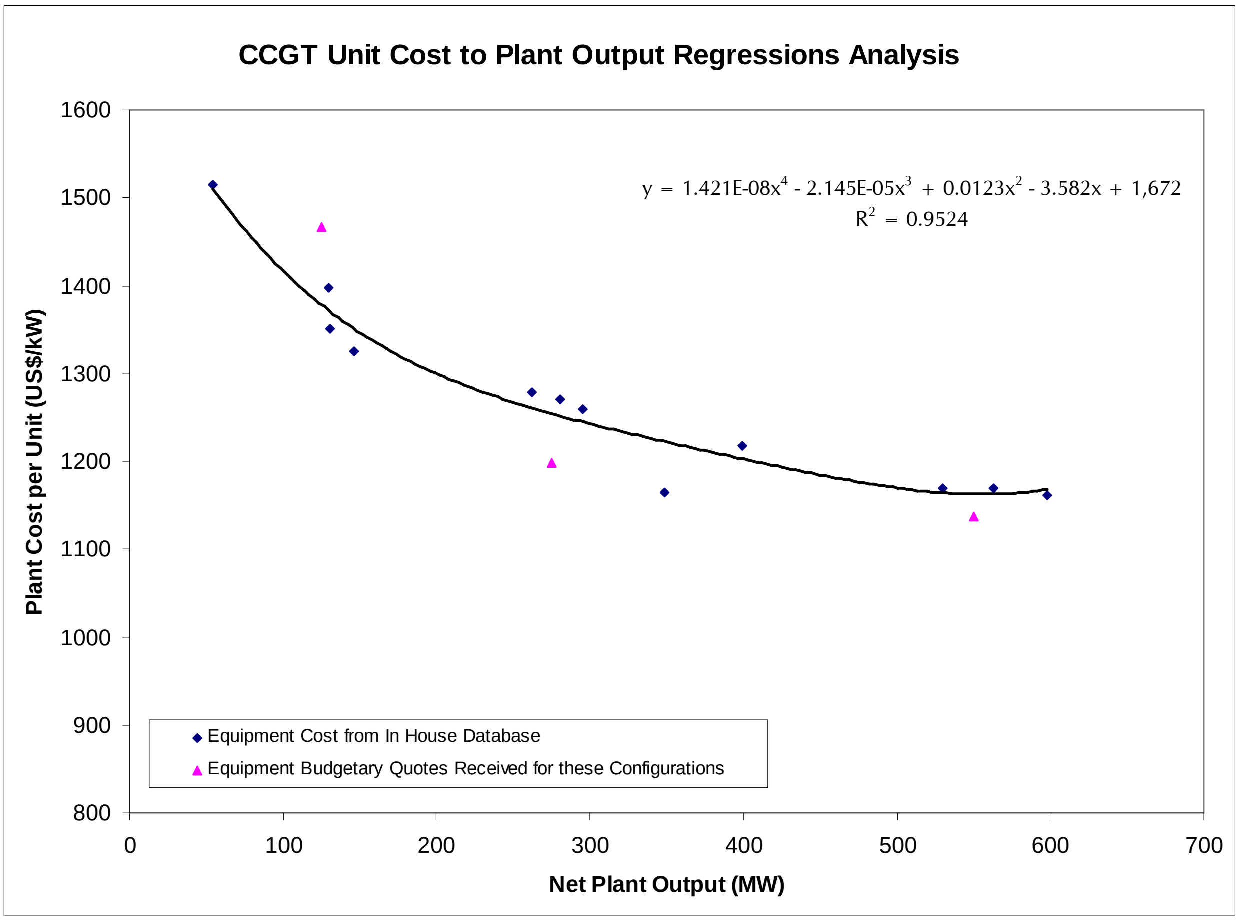


Figure 6.1 - Regression Analysis of CCGT Power Plant Cost Data

The results of this analysis show a trend of decreasing unit costs with increase in plant size. The slope of this curve decreases with increase in plant size. This behaviour can be explained by two major factors which are economies of scale as well as increasing plant complexity with size increase. The economies of scale factor results in reduced costs with increase in plant size whereas the plant complexity factor results in increasing plant costs with increase in plant size due to design, construction and planning complexities of a large plant.

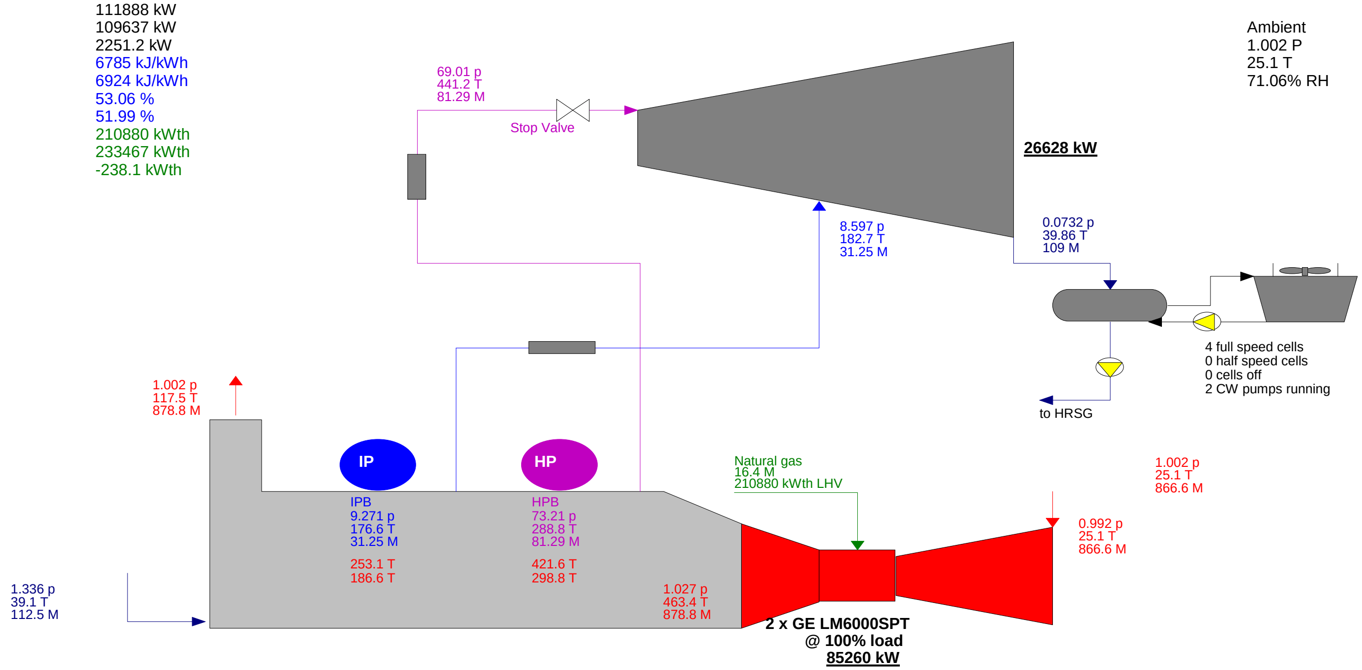
The regression analysis does indicate that a polynomial type function exists between unit capital cost and plant installed capacity. This is reflected by the high R square value of 95%, meaning that 95% of the variation in unit plant cost can be accounted for by plant output regression specification.

Appendix A

Energy and Mass Balances

GT MASTER 18.0 Hatch

Gross Power	111888 kW
Net Power	109637 kW
Aux. & Losses	2251.2 kW
LHV Gross Heat Rate	6785 kJ/kWh
LHV Net Heat Rate	6924 kJ/kWh
LHV Gross Electric Eff.	53.06 %
LHV Net Electric Eff.	51.99 %
Fuel LHV Input	210880 kWth
Fuel HHV Input	233467 kWth
Net Process Heat	-238.1 kWth



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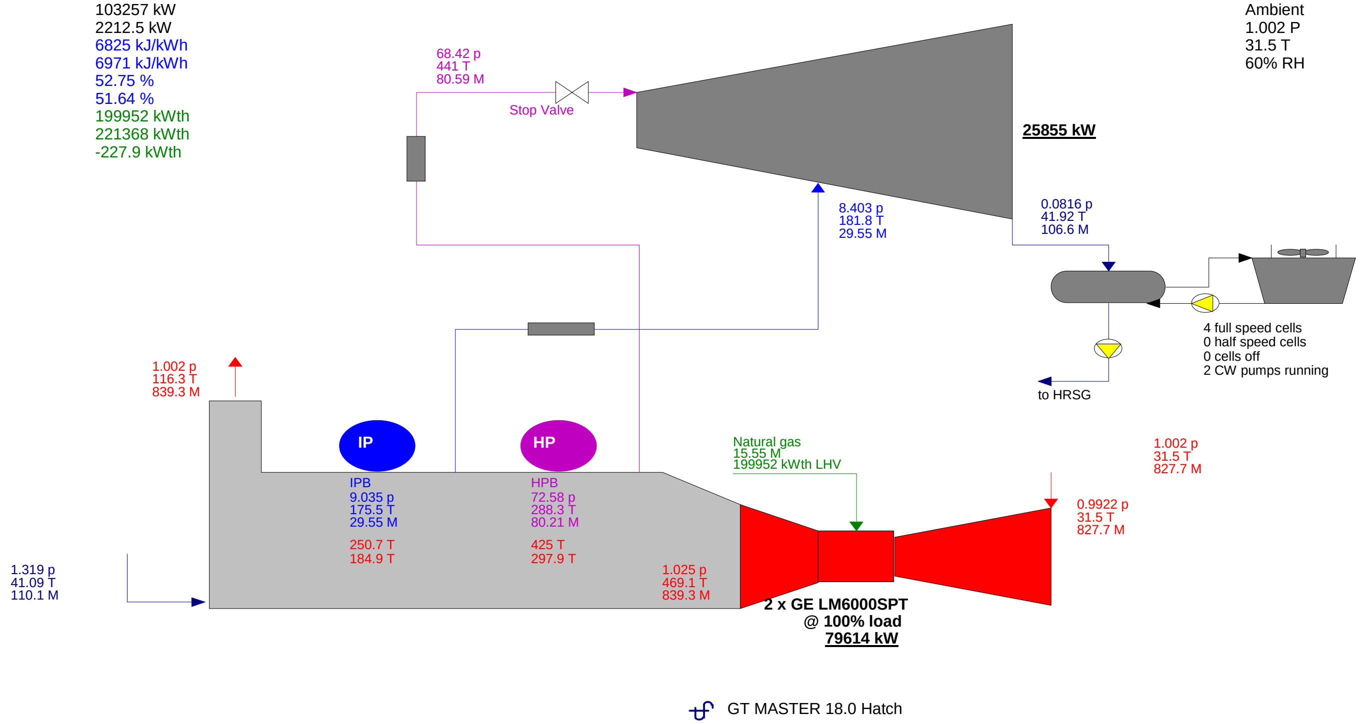
17 10-06-2008 14:45:35 file=C:\Projects\Lower Churchill-325967\Average\Average-Option-1-LM6000.GTM

GT MASTER 18.0 Hatch

GT MASTER 18.0 Hatch	
Gross Power	105469 kW
Net Power	103257 kW
Aux. & Losses	2212.5 kW
LHV Gross Heat Rate	6825 kJ/kWh
LHV Net Heat Rate	6971 kJ/kWh
LHV Gross Electric Eff.	52.75 %
LHV Net Electric Eff.	51.64 %
Fuel LHV Input	199952 kWth
Fuel HHV Input	221368 kWth
Net Process Heat	-227.9 kWth

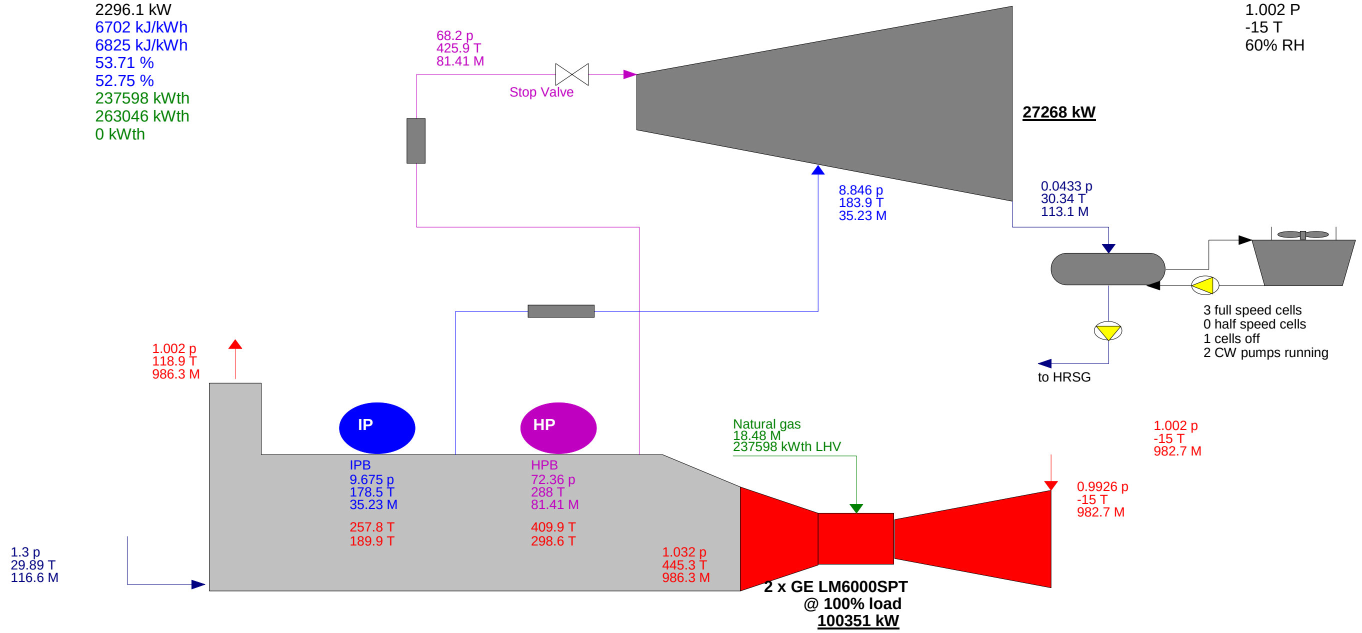


Average-Option-1-LM6000-summer.GTM

GT MASTER 18.0 Hatch

Gross Power	127619 kW
Net Power	125323 kW
Aux. & Losses	2296.1 kW
LHV Gross Heat Rate	6702 kJ/kWh
LHV Net Heat Rate	6825 kJ/kWh
LHV Gross Electric Eff.	53.71 %
LHV Net Electric Eff.	52.75 %
Fuel LHV Input	237598 kWth
Fuel HHV Input	263046 kWth
Net Process Heat	0 kWth

Ambient
1.002 P
-15 T
60% RH

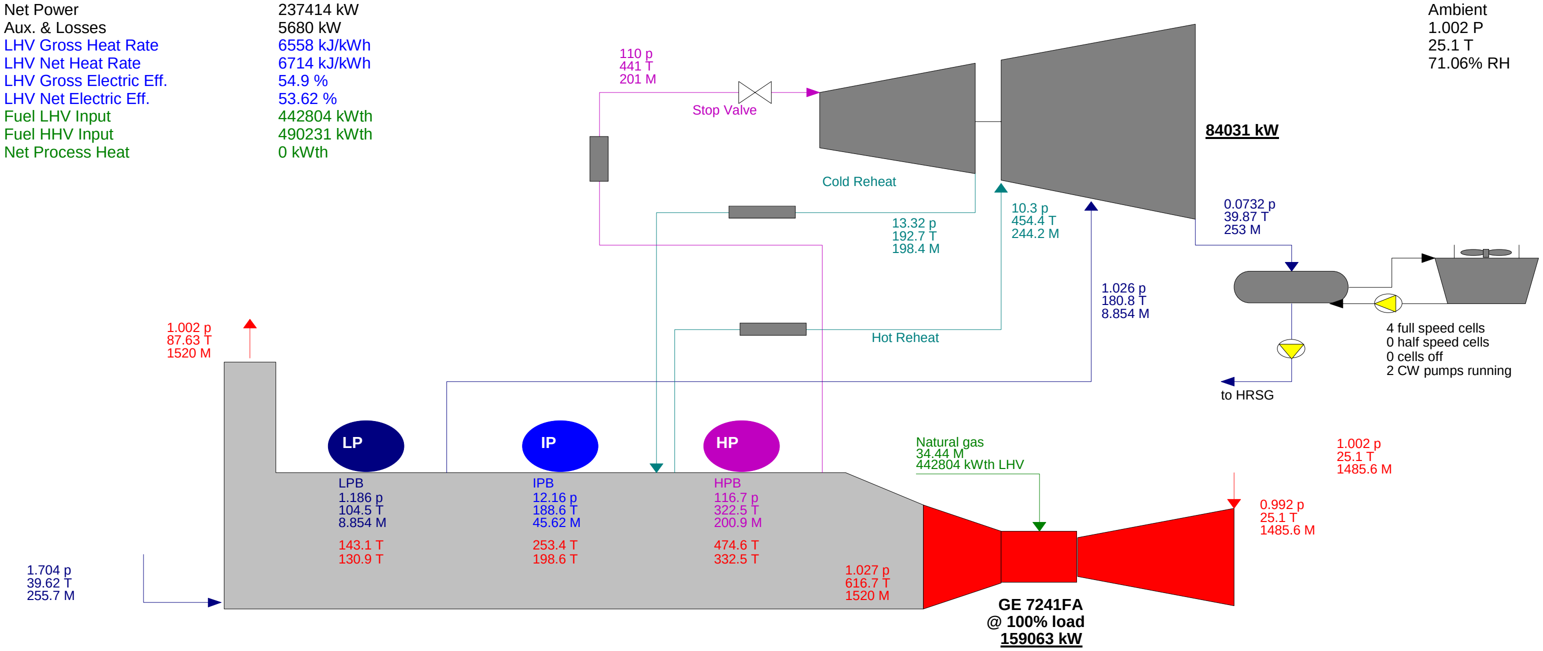


GT MASTER 18.0 Hatch

Average-Option-1-LM6000-winter.GTM

GT MASTER 18.0 Hatch

Gross Power	243095 kW
Net Power	237414 kW
Aux. & Losses	5680 kW
LHV Gross Heat Rate	6558 kJ/kWh
LHV Net Heat Rate	6714 kJ/kWh
LHV Gross Electric Eff.	54.9 %
LHV Net Electric Eff.	53.62 %
Fuel LHV Input	442804 kWth
Fuel HHV Input	490231 kWth
Net Process Heat	0 kWth

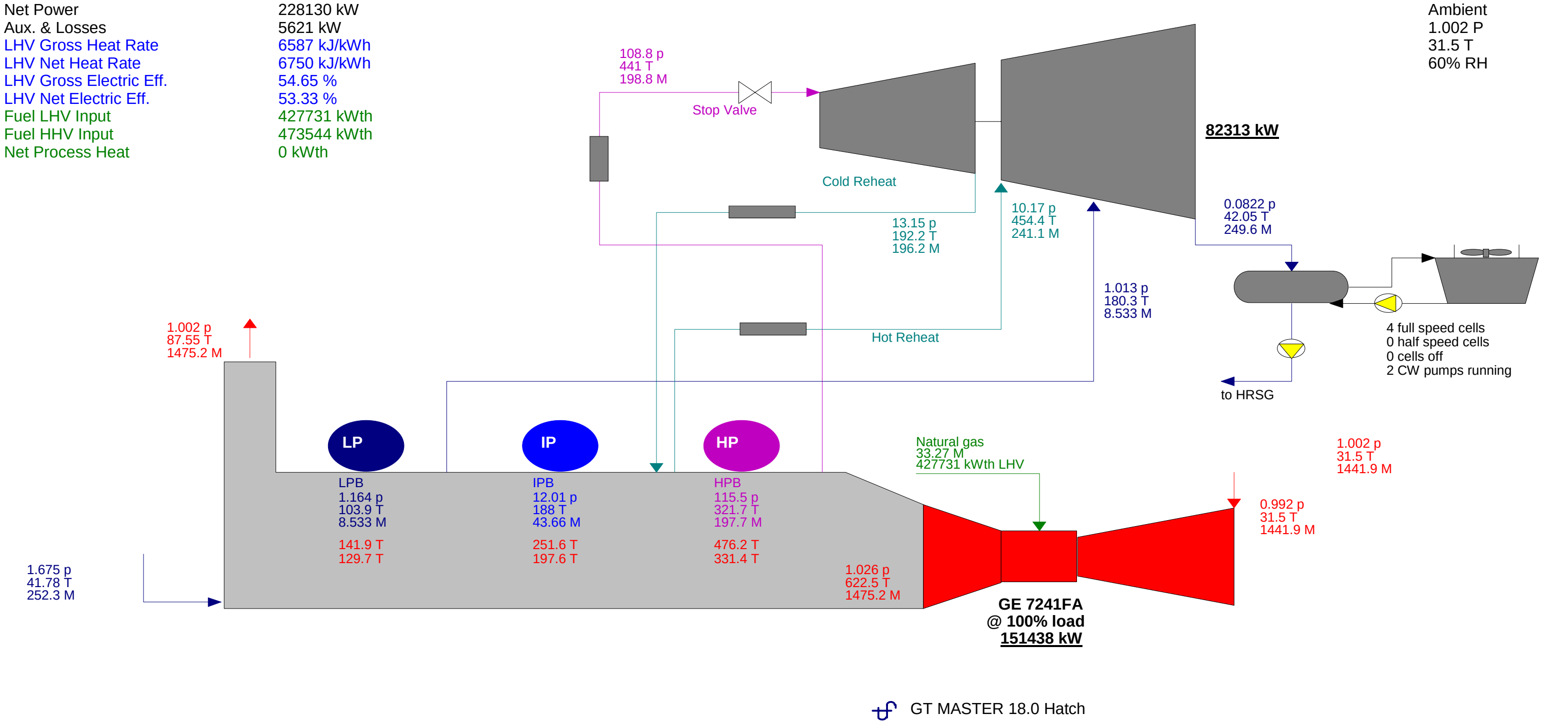


GT MASTER 18.0 Hatch

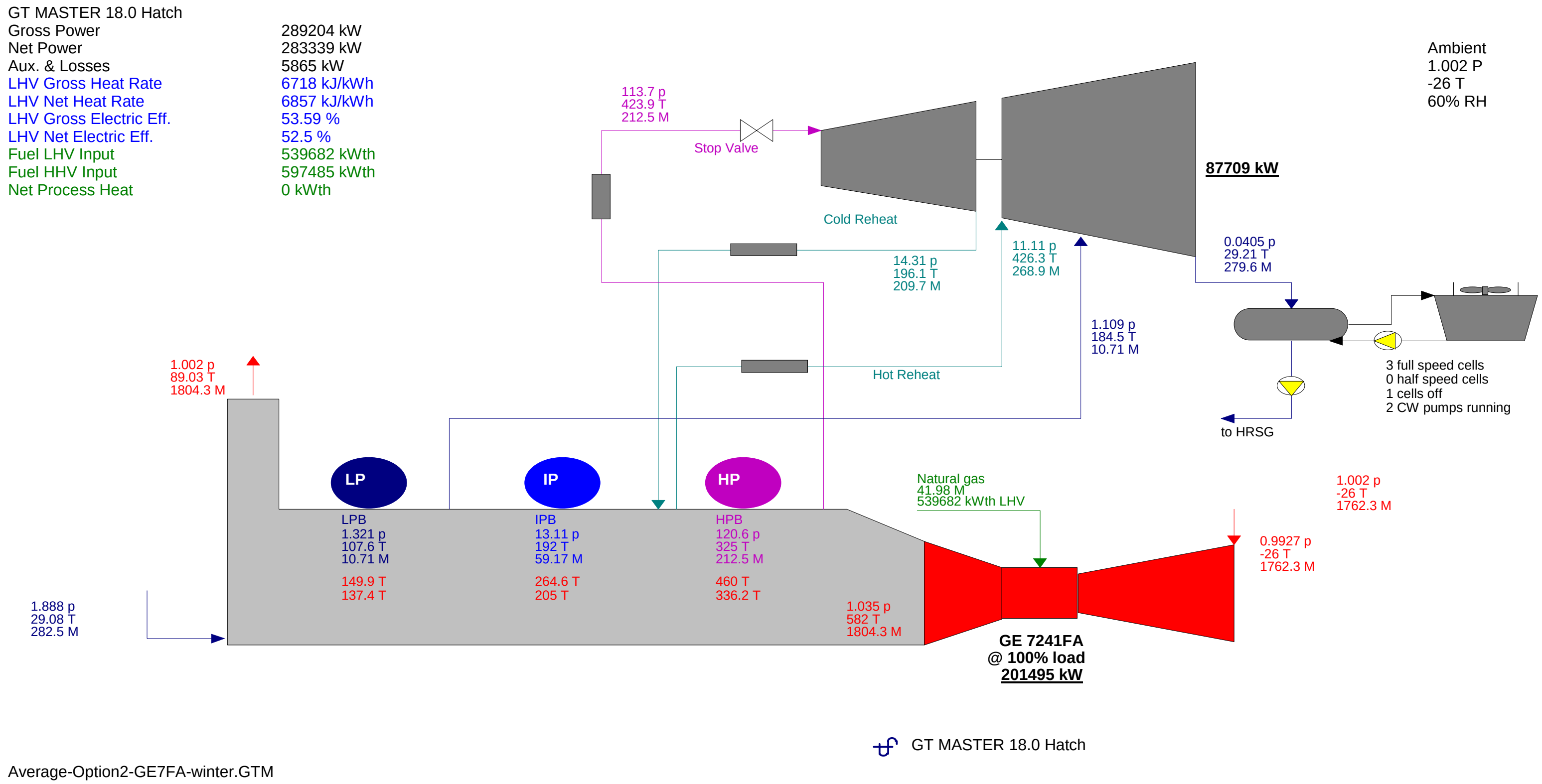
Average-Option2-GE7FA.GTM

GT MASTER 18.0 Hatch

Gross Power	233751 kW
Net Power	228130 kW
Aux. & Losses	5621 kW
LHV Gross Heat Rate	6587 kJ/kWh
LHV Net Heat Rate	6750 kJ/kWh
LHV Gross Electric Eff.	54.65 %
LHV Net Electric Eff.	53.33 %
Fuel LHV Input	427731 kWth
Fuel HHV Input	473544 kWth
Net Process Heat	0 kWth

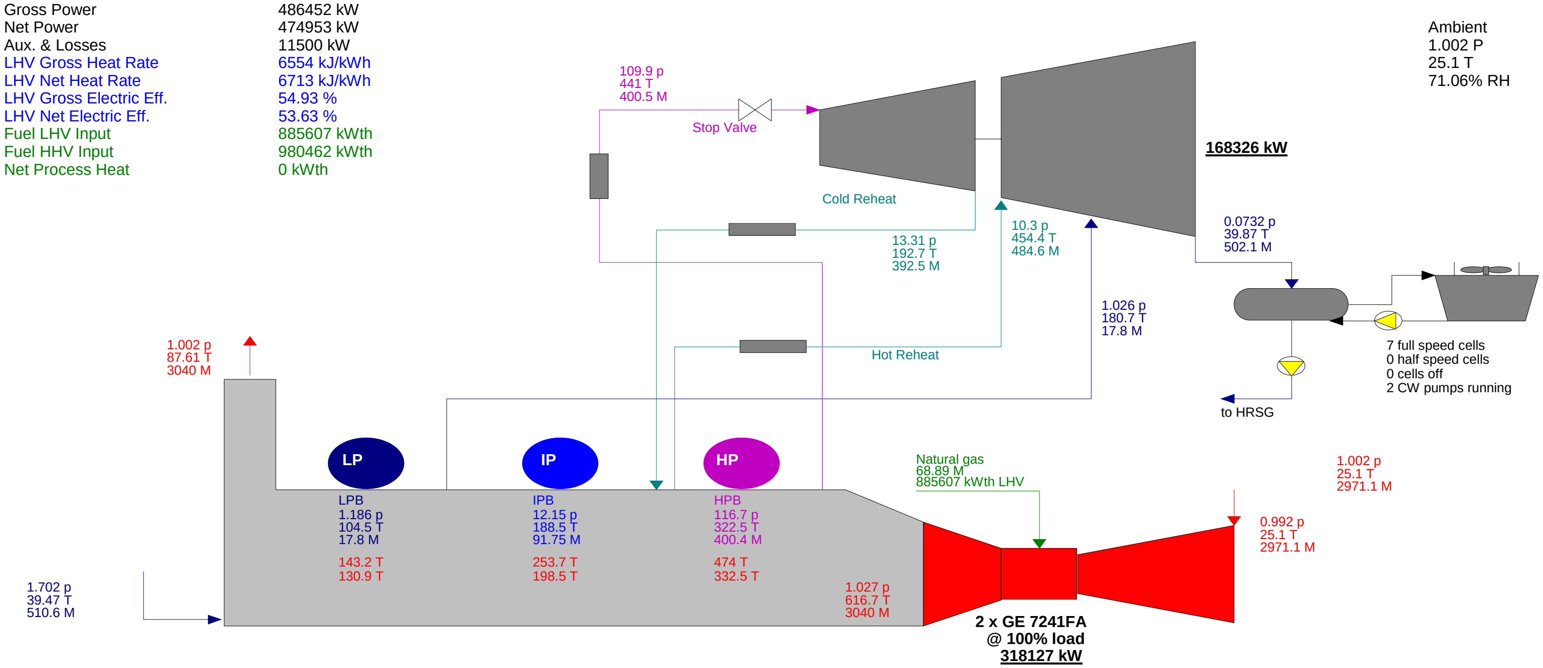


Average-Option2-GE7FA-summer.GTM


GT MASTER 18.0 Hatch
Gross Power 289204 kW
Net Power 283339 kW
Aux. & Losses 5865 kW
LHV Gross Heat Rate 6718 kJ/kWh
LHV Net Heat Rate 6857 kJ/kWh
LHV Gross Electric Eff. 53.59 %
LHV Net Electric Eff. 52.5 %
Fuel LHV Input 539682 kWth
Fuel HHV Input 597485 kWth
Net Process Heat 0 kWth
113.7 p
423.9 T
212.5 M
Stop Valve
Ambient
1.002 P
-26 T
60% RH
87709 kW
Cold Reheat
14.31 p
196.1 T
209.7 M
11.11 p
426.3 T
268.9 M
0.0405 p
29.21 T
279.6 M
1.109 p
184.5 T
10.71 M
Hot Reheat
3 full speed cells
0 half speed cells
1 cells off
2 CW pumps running
to HRSG
1.002 p
89.03 T
1804.3 M
LP
IP
HP
Natural gas
41.98 M
539682 kWth LHV
1.002 p
-26 T
1762.3 M
LPB
1.321 p
107.6 T
10.71 M
149.9 T
137.4 T
IPB
13.11 p
192 T
59.17 M
264.6 T
205 T
HPB
120.6 p
325 T
212.5 M
460 T
336.2 T
0.9927 p
-26 T
1762.3 M
1.888 p
29.08 T
282.5 M
1.035 p
582 T
1804.3 M
GE 7241FA
@ 100% load
201495 kW
GT MASTER 18.0 Hatch
Average-Option2-GE7FA-winter.GTM

GT MASTER 18.0 Hatch

Gross Power	486452 kW
Net Power	474953 kW
Aux. & Losses	11500 kW
LHV Gross Heat Rate	6554 kJ/kWh
LHV Net Heat Rate	6713 kJ/kWh
LHV Gross Electric Eff.	54.93 %
LHV Net Electric Eff.	53.63 %
Fuel LHV Input	885607 kWth
Fuel HHV Input	980462 kWth
Net Process Heat	0 kWth

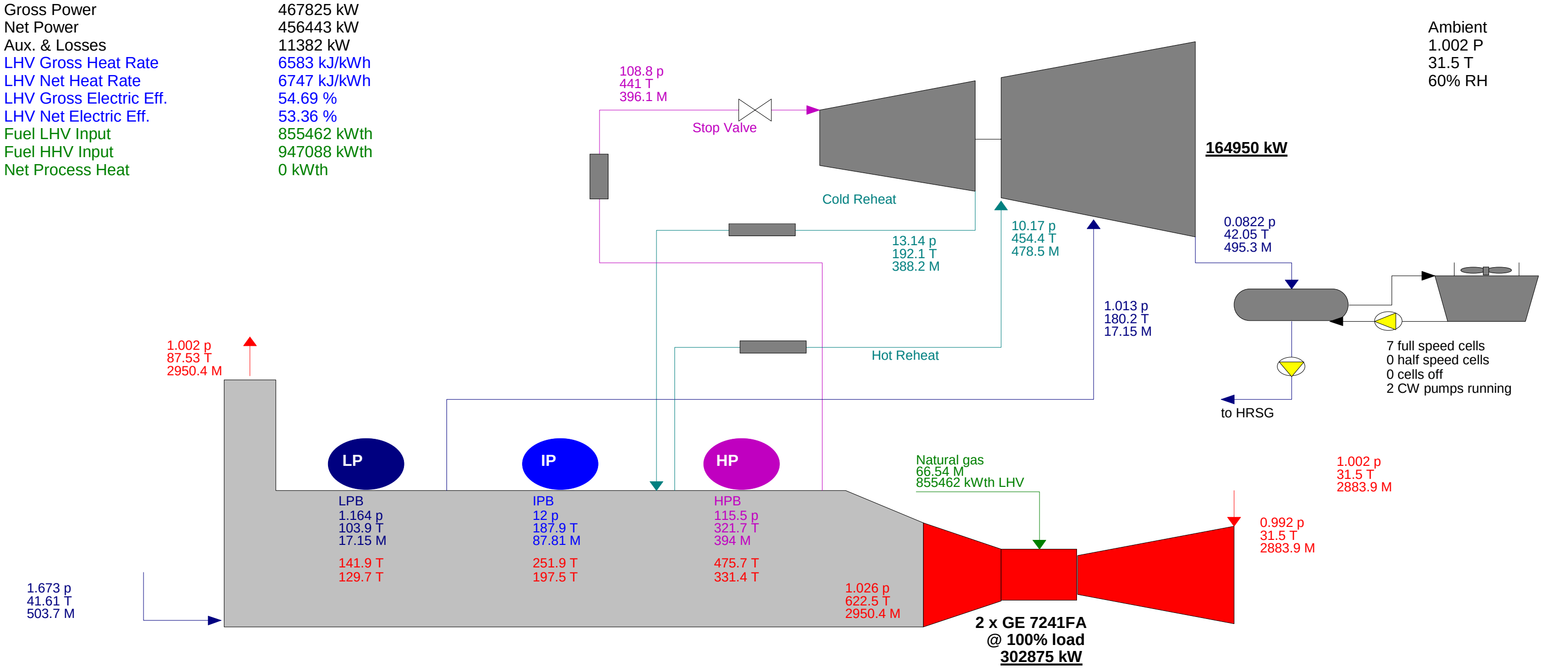


GT MASTER 18.0 Hatch

Average-Option 3-GE7FA.GTM

GT MASTER 18.0 Hatch

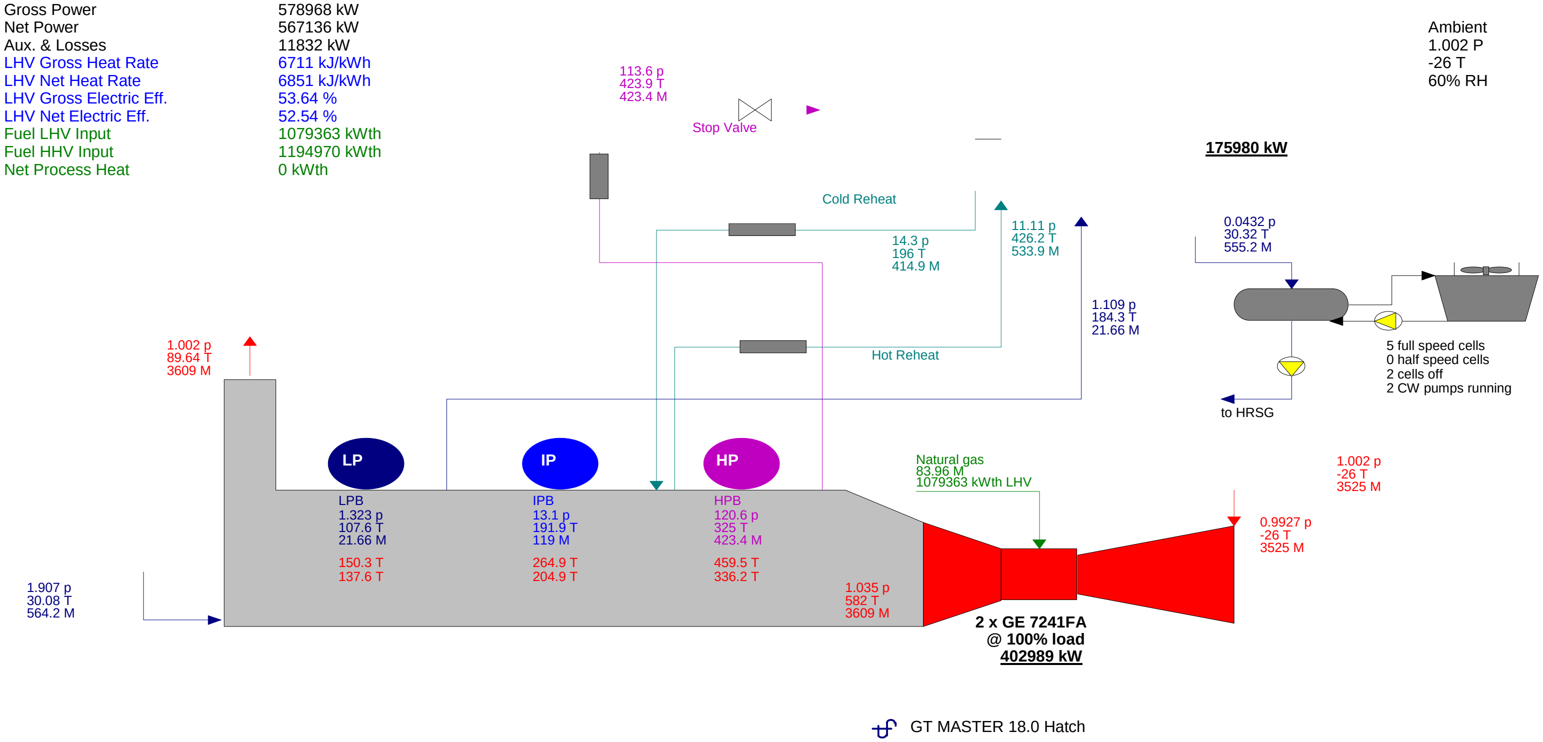
Gross Power	467825 kW
Net Power	456443 kW
Aux. & Losses	11382 kW
LHV Gross Heat Rate	6583 kJ/kWh
LHV Net Heat Rate	6747 kJ/kWh
LHV Gross Electric Eff.	54.69 %
LHV Net Electric Eff.	53.36 %
Fuel LHV Input	855462 kWth
Fuel HHV Input	947088 kWth
Net Process Heat	0 kWth



GT MASTER 18.0 Hatch

Average-Option 3-GE7FA-summer.GTM

GT MASTER 18.0 Hatch	
Gross Power	578968 kW
Net Power	567136 kW
Aux. & Losses	11832 kW
LHV Gross Heat Rate	6711 kJ/kWh
LHV Net Heat Rate	6851 kJ/kWh
LHV Gross Electric Eff.	53.64 %
LHV Net Electric Eff.	52.54 %
Fuel LHV Input	1079363 kWth
Fuel HHV Input	1194970 kWth
Net Process Heat	0 kWth



Average-Option 3-GE7FA-winter.GTM